Technical Memo

ANL/EES-TM-314

IMPACTS ON INDIVIDUAL INDUSTRIAL BOILERS OF ALTERNATIVE NEW SOURCE PERFORMANCE STANDARDS FOR SULFUR DIOXIDE

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by

D.A. Knudson, T.D. Veselka, and D.W. South

Energy and Environmental Systems Division
Policy and Economic Analysis Group

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SUMMARY

This report presents an analysis of the cost impacts of several regulatory options for new industrial, commercial, and institutional coal-fired boilers.* The motivation for the analysis was the proposed revision to the industrial boiler new source performance standards (NSPS) for sulfur dioxide (SO_2) (40 CFR §60 Subpart D). Current standards limit SO_2 emissions to 1.2 lb $SO_2/10^6$ Btu for coal-fired units with heat input greater than 250 x 10^6 Btu/h.‡ Proposed revisions to this standard would require a 90% reduction in emissions and impose an emission ceiling of 1.2 lb $SO_2/10^6$ Btu for boilers with heat input greater than 100 x 10^6 Btu/h (51 Fed. Reg. 22384: June 19, 1986). These revisions represent two major changes in industrial boiler NSPS for SO_2: (1) reducing the minimum applicable boiler size from 250 x 10^6 Btu/h to 100 x 10^6 Btu/h and (2) requiring a mandatory 90% SO_2 emission reduction.

This study presents an independent analysis by Argonne National Laboratory (ANL) of the relevant costs and emission reduction potential from compliance with the proposed NSPS revisions. These results are contrasted with several alternative regulatory options for industrial boiler SO_2 NSPS. The regulatory impact analysis conducted by the U.S. Environmental Protection Agency (EPA) was reviewed and provides the basis for much of the information contained in this report. Published EPA information, supplemented with appropriate independent data, was used to compute the annualized costs and cost-effectiveness (in dollars per ton of SO_2 removed) for a variety of potentially viable regulatory options.

The cost-effectiveness measure is being used by EPA to evaluate the reasonableness of the proposed revision to NSPS for industrial boiler SO_2 emissions. For this reason, it is the basis for comparison of regulatory options in this report. Cost-effectiveness is defined here as the difference in cost per ton of SO_2 removed between the relevant regulatory baseline and the appropriate regulatory option. As such, the larger the cost-effectiveness value, the more costly it is to remove a ton of SO_2. In the computation of cost-effectiveness, the definition of the regulatory baseline is an

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*For the remainder of this report, the term *industrial* will refer to these three sectors.

‡For convenience throughout the remainder of this report, boiler size will be expressed simply as, for example, 250 x 10^6 Btu/h. This expression should be taken to refer explicitly to gross heat input.

important factor. In this study, several regulatory baselines were examined to illustrate the sensitivity of cost-effectiveness estimates to baseline assumptions.

Among the major findings of this analysis are four key results:

- The baseline emission rate used by EPA is considerably less stringent than typical emission rates contained in EPA-approved permits. The EPA analysis of the proposed standard produced lower cost-effectiveness values than would occur if typical emission rates were used.

- A requirement for continuous emissions monitoring (CEM) distorts the cost and cost-effectiveness of compliance-coal options versus technology-dependent approaches such as flue-gas desulfurization (FGD). For some small boilers, the annual costs of monitoring would exceed the annual costs of emissions compliance.

- Projections of the amount of coal burned in new industrial boilers are contingent on assumptions about future fuel prices. Based on a simplified comparison of total levelized costs for coal- and oil-fired boilers, oil prices would have to rise to $35-45/bbl in order for coal to compete effectively as an industrial boiler fuel. With natural gas and residual oil prices projected to be $26/bbl and $24/bbl (in 1983 dollars) in the year 2000, respectively, there is little incentive to construct new coal-fired industrial boilers. Thus, EPA may be overstating the environmental benefits (i.e., reduced emissions) of the proposed revision.

- Nonfossil fuel credits can be significant for coal-fired, combined-cycle cogeneration or multifuel boilers in situations where there is a marginal choice between compliance coal and FGD. For certain emission ceilings, the credit may allow use of lower-cost compliance-coal options.

Study Approach

The costs of new coal-fired boilers meeting specific regulatory requirements were estimated with boiler and control system cost algorithms and a set of coal costs published by EPA. This information formed the basis for constructing a new model, the New Industrial Boiler (NIB) model. Data on coal cleaning characteristics and a second set of coal costs were also included in the NIB model. These alternative coal costs were derived from the output of the Advanced Utility Simulation Model (AUSM), with appropriate modifications for applicability to the industrial sector.

The NIB model computes the least-cost method of meeting an SO_2 emission regulation. The model uses regional fuel costs and FGD control cost algorithms to determine the least-cost control method based on boiler location, size, and annual capacity factors (utilization rates). Three methods of emissions control are considered: coal selection (including blending), coal cleaning, and the installation of FGD systems. Several FGD technology choices are included. The NIB model selects a single control method, or a combination of two or more control methods, to arrive at a least-cost solution for complying with a specific regulatory requirement.

The regulatory baseline defines the emission rate and operating cost of new coal-fired boilers, given no change in current regulations. Determining an appropriate baseline is important because it affects all subsequent cost-effectiveness computations. The existing emission limit for new coal-fired boilers greater than 250 x 10^6 Btu/h is 1.2 lb $SO_2/10^6$ Btu. Because available permit data show adherence to this limit, it is used in this study as the regulatory baseline for boilers equal to or greater than 250 x 10^6 Btu/h.

Determining a suitable baseline for new boilers greater than 100 and less than 250 x 10^6 Btu/h heat input is more difficult because emission limits for boilers in this range are determined on a case-by-case basis. Available information on emission limits for recent permits indicates that for eastern regions (Federal Regions 1-5 and 7), a value of 1.6 lb $SO_2/10^6$ Btu appears to be a reasonable regulatory baseline estimate. In the western regions (Regions 6 and 8-10), based on the small available sample, a value of 1.2 lb $SO_2/10^6$ Btu appears reasonable.

In sum, the emission rates used for the regulatory baseline in this study are:

- 1.2 lb $SO_2/10^6$ Btu for all coal-fired industrial boilers greater than 250 x 10^6 Btu/h,
- 1.6 lb $SO_2/10^6$ Btu for coal-fired boilers between 100 and 250 x 10^6 Btu/h in the East (Regions 1-5 and 7), and
- 1.2 lb $SO_2/10^6$ Btu for coal-fired boilers between 100 and 250 x 10^6 Btu/h in the West (Regions 6 and 8-10).

This regulatory baseline is referred to as the ANL baseline. In contrast, the baseline emission rate selected by EPA in its model boiler analysis was 2.5 lb $SO_2/10^6$ Btu for all boiler sizes and regions. The ANL estimates are supported by recent EPA permit information and describe potential emission reductions and costs more accurately.

In this study, a number of potentially viable regulatory options were evaluated against the regulatory baseline used by ANL:

- 1979 utility NSPS (40 CFR §60 Subpart Da),
- 90% mandatory removal with a 0.8 lb $SO_2/10^6$ Btu ceiling,
- 70% mandatory removal with a 0.8 lb $SO_2/10^6$ Btu ceiling, and
- Emission ceilings ranging from 0.2 through 1.4 lb $SO_2/10^6$ Btu, with and without CEM requirements for compliance fuels.

For each regulatory option, the NIB model was run for 100, 250, and 400 x 10^6 Btu/h coal-fired boilers with annual capacity factors of 0.6 and 0.4 in each of the 10 federal regions. The results summarized below are for boilers operating at a capacity factor of 0.6 in three regions: one in the East (Region 3), one in the Midwest (Region 5), and one in the West (Region 8).

In addition to these regulatory options, a number of other contingent issues were evaluated: credits for cogeneration and nonfossil fuel combustion, the impact of alternative coal prices, and the comparative costs of firing a boiler with coal versus oil.

Study Findings

Regulatory Baseline. Because the regulatory baseline affects all subsequent computations of cost-effectiveness, the sensitivity of cost-effectiveness to a broad range of regulatory baselines was analyzed. This sensitivity analysis indicated that the regulatory baseline can have a substantial effect on cost-effectiveness. Figures S.1-S.3 illustrate the effects of different baseline assumptions on cost-effectiveness for various combinations of emission limit, boiler size, and region. Three baseline scenarios are compared: the EPA baseline, the ANL baseline with continuous monitoring required, and the ANL baseline without continuous monitoring required. If other parameters are held constant, the alternative regulatory options are much less cost-effective (e.g., values in $/ton are roughly twice as large) when the ANL baseline is used, as compared with the EPA baseline.

Mandatory Percentage Removal Options. Model results for mandatory percentage removal regulatory options are summarized below.

- For 100 x 10^6 Btu/h boilers, cost-effectiveness estimates are $1,700-$2,500/ton.

- For 250 and 400 x 10^6 Btu/h boilers, cost-effectiveness estimates are about $1,500 and $1,000/ton, respectively.

- The only boilers that achieve a cost-effectiveness of less than $1,000/ton for any of the mandatory percentage removal requirement options examined are 400 x 10^6 Btu/h boilers in Region 3. Cost-effectiveness is lower for this case because the NIB model determines that these boilers would use FGD systems to meet the current regulatory baseline; hence, any cost increase under the regulatory scenario only reflects the cost of increasing FGD removal efficiency and not the total scrubber cost.

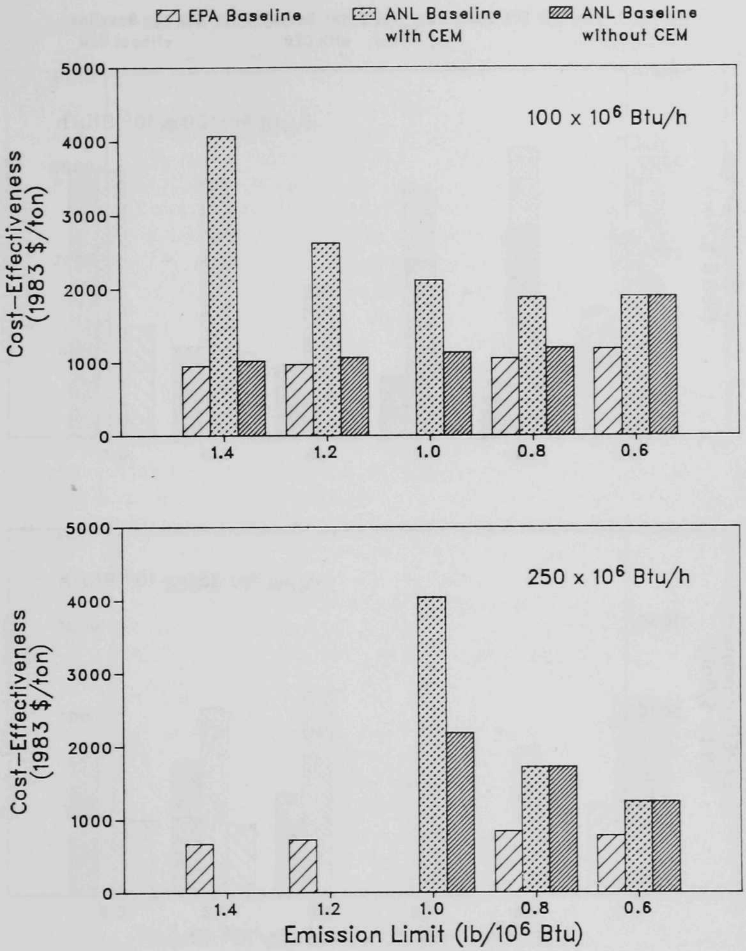

FIGURE S.1 Effect of Different Regulatory Baselines on the Cost-Effectiveness of Various SO_2 Emission Ceilings, by Boiler Size: Region 3

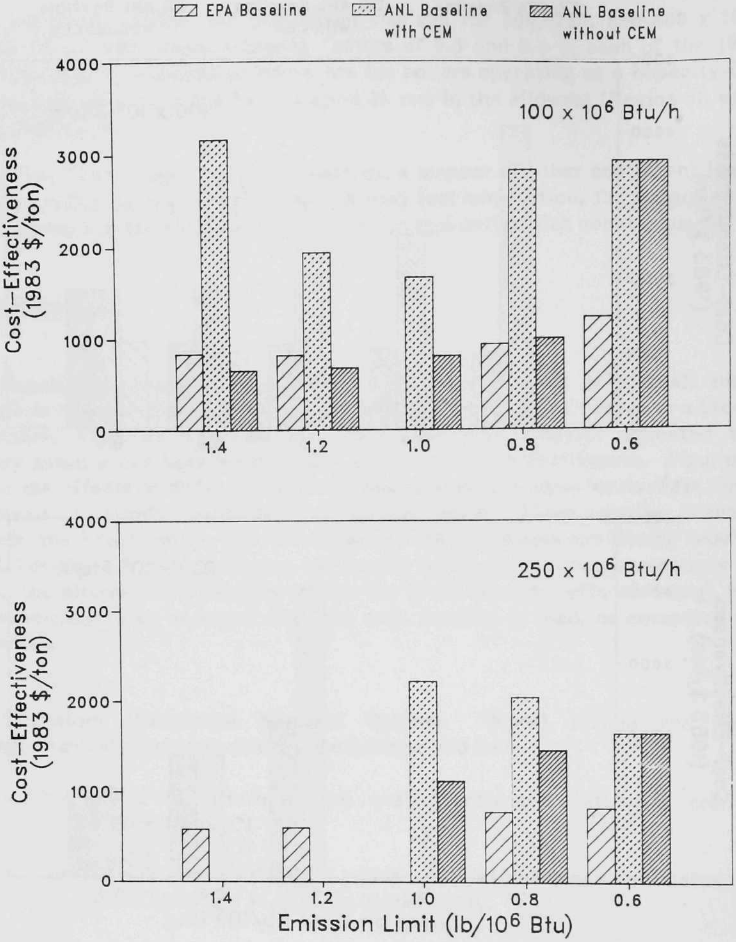

FIGURE S.2 Effect of Different Regulatory Baselines on the Cost-Effectiveness of Various SO_2 Emission Ceilings, by Boiler Size: Region 5

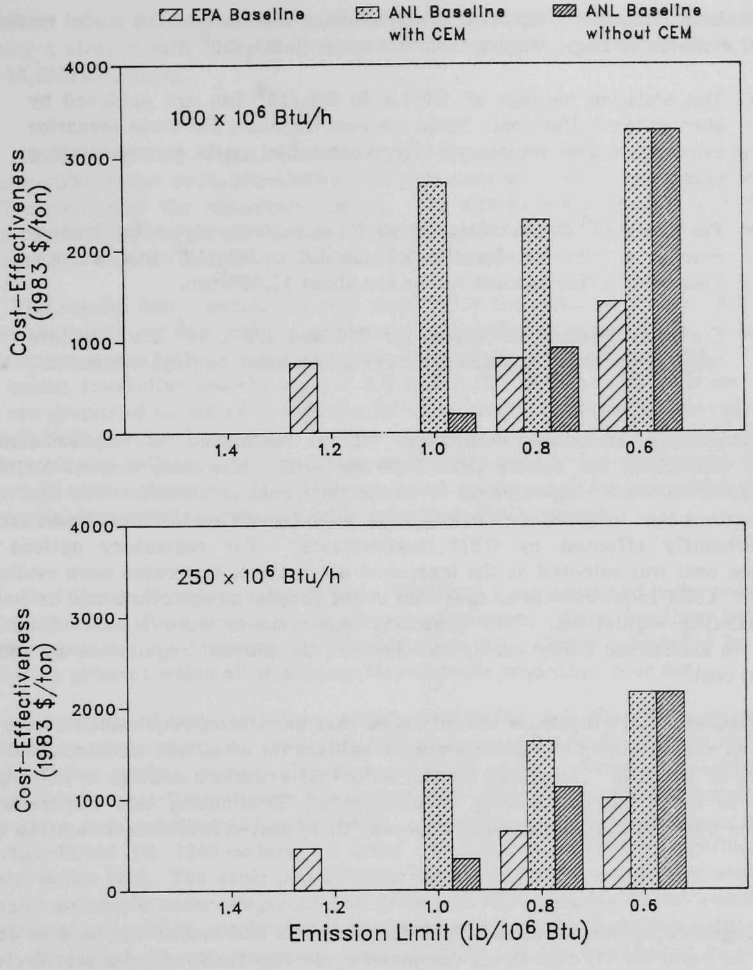

FIGURE S.3 Effect of Different Regulatory Baselines on the Cost-Effectiveness of Various SO_2 Emission Ceilings, by Boiler Size: Region 8

Emission Limitation Options. The following summarizes the model results for a variety of emission ceilings, ranging from 0.2 to 1.4 lb $SO_2/10^6$ Btu.

- The emission ceilings of 1.0-1.4 lb $SO_2/10^6$ Btu are achieved by burning low-sulfur coal. Thus, the cost increases for these scenarios are largely attributable to incremental fuel costs and monitoring costs.

- For 100 x 10^6 Btu/h boilers in all three regions, cost-effectiveness reaches a minimum for the 0.8 and 1.0 lb $SO_2/10^6$ Btu ceilings. These cost-effectiveness values are about $2,000/ton.

- Cost-effectiveness estimates for 250 and 400 x 10^6 Btu/h boilers range from $1,000 to $4,000/ton for all emission ceilings evaluated.

Continuous Emissions Monitoring. It is reasonable to require continuous emissions monitoring for boilers with FGD systems. However, current NSPS allow exemptions from CEM requirements if compliance coal is burned. The EPA did not analyze options that included such exemptions, even though cost-effectiveness estimates are significantly affected by CEM requirements. For regulatory options where compliance coal was selected as the least-cost alternative, two cases were evaluated in this study: CEM requirements as specified in the proposed regulations and as contained in the existing regulations. The proposed requirements were simulated by adding $110,000 to annualized boiler costs, and those in the current regulations by adding no additional cost.

Figures S.1-S.3 illustrate the influence that monitoring requirements have on the overall cost-effectiveness of various emission ceilings for small and medium-sized boilers in Regions 3, 5, and 8. The graphs clearly show that emissions ceilings in all ranges are sensitive to continuous monitoring requirements. Eliminating this requirement for compliance coal options considerably improves their cost-effectiveness relative to FGD options.

Cogeneration and Nonfossil Fuel Credits. The NIB model was used to compute SO_2 control costs for (1) coal-fired, combined-cycle cogeneration units that derive part of their heat from the exhaust of turbines firing distillate oil or natural gas and (2) boilers that burn a mixture of coal and wood. When combined fuels are examined, allowing credit for heat input from clean (low-sulfur) fuel has the effect of permitting a higher sulfur content in the other fuel. The analysis of emission credits is based on a comparison of systems receiving and not receiving credit for cogeneration and nonfossil fuel combustion.

The analysis of credits for burning nonfossil fuel was confined to Regions 1, 4, and 10, where most nonfossil boiler fuel is consumed. It was assumed that these boilers receive 25% of their heat input from nonfossil fuel. In general, the additional cost for boilers with FGD systems, regardless of credit, is $300-$500/ton. For boilers that are not required to use FGD under the credited scenario, but that must resort to using FGD or burning a cleaner coal under the noncredited scenario, the additional costs are in the \$1,500-\$3,000/ton range.

Alternative Coal Prices. Because of the importance of fuel prices in estimating total annualized boiler cost, alternative coal cost data were also used in calculating the cost-effectiveness of the regulatory options. The alternative coal costs were based on those in the AUSM Coal Supply Module. These alternative cost data include a very-low-sulfur coal that was not available in the EPA coal data base.

The results from running the NIB model with the alternative coal data indicate that the availability of low-sulfur coal, even at a significant premium, can cause a shift away from selecting FGD to meet low emission ceilings. In Region 3, 400 x 10^6 Btu/h boilers select low-sulfur coal to meet a 1.0 lb $SO_2/10^6$ Btu ceiling, whereas the same boilers are predicted to use FGD with the EPA coal data. Similarly, in this region, 250 x 10^6 Btu/h boilers select low-sulfur coal to meet a ceiling of 0.8 lb $SO_2/10^6$ Btu. The analysis generally indicates that, given the availability of very-low-sulfur coal, the least-cost method of complying with moderate emission ceilings is firing low-sulfur coal, even at substantial incremental cost, instead of relying on FGD systems.

Coal Use in New Industrial Boilers. The final issue examined is the potential for installing new coal-fired boilers under current regulations. Total levelized boiler costs for firing coal and oil (meeting the regulatory baseline) were calculated in order to estimate the price at which oil would lose its economic advantage over coal.

The results of that analysis are summarized in Fig. S.4. The figure shows that, in the relatively near future, oil (and gas) will compete effectively for the bulk of the industrial boiler market, since projected residual oil and gas prices are markedly below the level where coal-fired boilers are economic.* With current technologies and for boilers up to and including 400 x 10^6 Btu/h, oil prices would generally have to rise to about \$35-45/bbl (in 1983 dollars) in order for coal to compete effectively as an industrial boiler fuel. The exception is larger industrial boilers in the West where coal is marginally economic under projected fuel price and high capacity factor conditions. If more-stringent standards are imposed, the price of oil at the crossover point would be higher. Projected oil and gas prices through 2000 are not anticipated to rise above \$30/bbl, and in the near term are around \$20/bbl (in 1983 dollars).

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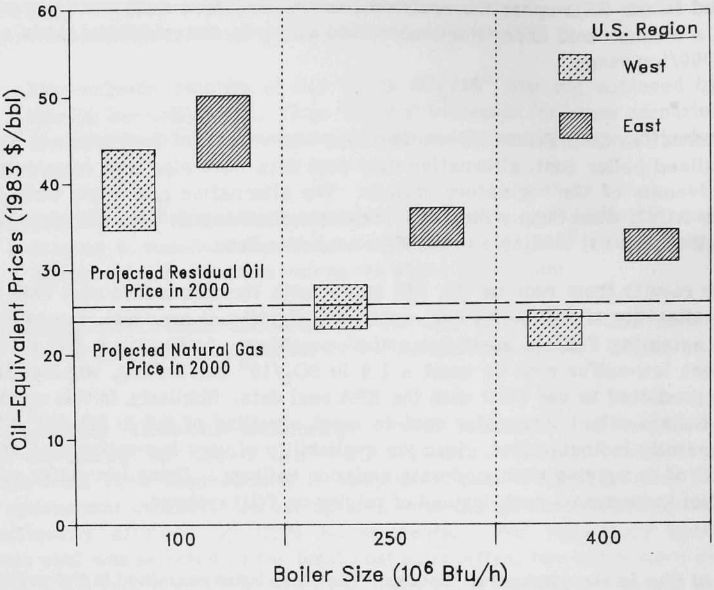
*Projected oil and gas prices were obtained from *Energy Review*, Data Resources, Inc., Lexington, Mass. (Summer 1986).



Note: The crossover point price depends on the capacity factor (CF), with the upper bound of each bar representing a 0.4 CF and the lower bound a 0.6 CF. As an example of how the bars should be interpreted, for a 100 x 10^6 Btu/h boiler in the West, oil prices must be at least $35/bbl at a 0.6 CF (or $44/bbl at a 0.4 CF) for a coal-fired boiler to be cost-effective.

FIGURE S.4 Range of Crossover Prices between Oil- and Coal-Fired Boilers, Relative to Projected Fuel Prices (Expressed in Oil-Equivalent Prices)

1 INTRODUCTION

This report presents an analysis of the cost impacts of several regulatory options for new industrial, commercial, and institutional coal-fired boilers.* The motivation for the analysis was the proposed revision to the industrial boiler new source performance standards (NSPS) for sulfur dioxide (SO_2) (40 CFR §60 Subpart D). Current standards limit SO_2 emissions to 1.2 lb $SO_2/10^6$ Btu for coal-fired units with greater than 250 x 10^6 Btu/h heat input capacity.‡ Proposed revisions to this standard would require a 90% reduction in emissions and impose an emission ceiling of 1.2 lb $SO_2/10^6$ Btu for boilers greater than 100 x 10^6 Btu/h heat input (51 Fed. Reg. 22384: June 19, 1986). These revisions represent two major changes in industrial boiler NSPS for SO_2: (1) reducing the minimum applicable boiler size from 250 x 10^6 Btu/h to 100 x 10^6 Btu/h and (2) requiring a mandatory 90% SO_2 emission reduction.

These revisions could potentially affect a large segment of the total coal-fired industrial capacity because 64% of that capacity (as of 1978)[1] is greater than 100 x 10^6 Btu/h and, of this large-boiler capacity, 30% is between 100 and 250 x 10^6 Btu/h.§ Estimates of SO_2 emissions in 1984 from coal-fired industrial boilers are 1.3 x 10^6 tons for boilers greater than 100 x 10^6 Btu and 0.62 x 10^6 tons for boiler sizes between 100 and 250 x 10^6 Btu. These values represent approximately 6% and 3%, respectively, of total annual SO_2 emissions in 1984.

This study presents an independent analysis by Argonne National Laboratory (ANL) of the relevant costs and emission reduction potential from compliance with the proposed NSPS revisions. These results are contrasted against several alternative regulatory options for industrial boiler SO_2 NSPS. The regulatory impact analysis conducted by the U.S. Environmental Protection Agency (EPA) was reviewed and provides the basis for much of the information contained in this report. Published EPA information, supplemented with appropriate independent data, was used to compute the annualized costs and cost-effectiveness (in dollars per ton of SO_2 removed) for a variety of potentially viable regulatory options.

The cost-effectiveness measure is being used by EPA to evaluate the reasonableness of the proposed revision to NSPS for industrial boiler SO_2 emissions.[2] For this reason, it is the basis for comparison of regulatory options in this report.

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*For the remainder of this report, the term *industrial* will refer to these three sectors.

‡For convenience throughout the remainder of this report, boiler size will be expressed simply as, for example, 250 x 10^6 Btu/h. This expression should be taken to refer explicitly to gross heat input.

§Based on sales data for coal-fired water-tube boilers, about 67% of the coal-fired boiler capacity purchased during 1965-1977 was in the food (Standard Industrial Classification [SIC] code 20), paper and allied products (SIC 26), chemicals and allied products (SIC 28), and transportation industry groups.[1] This information suggests the distribution of coal-fired boilers in service by industry.

Cost-effectiveness is defined here as the difference in cost per ton of SO_2 removed between the relevant regulatory baseline and the appropriate regulatory option. As such, the larger the value of cost-effectiveness, the more costly it is to remove a ton of SO_2.

The regulatory baseline defines the emission rate and cost of operating new coal-fired boilers, given no change in current regulations. Determining an appropriate baseline is important because it affects all subsequent cost-effectiveness computations. Hence, in this study, several regulatory baselines were examined to illustrate the sensitivity of cost-effectiveness estimates to baseline assumptions. Among the regulatory options assessed were various emission ceilings and mandatory percentage removal requirements. Also assessed were the effects of (1) credits for cogeneration and nonfossil fuel combustion and (2) continuous emissions monitoring (CEM) requirements on the cost-effectiveness of the regulatory options.

For the analysis, a new model was developed to compute the cost of meeting an SO_2 emission regulation for new coal-fired boilers. A description of the model is provided in Sec. 2, along with a more-detailed explanation of the study methodology. Alternative regulatory baselines are examined in Sec. 3, and the cost-effectiveness of regulatory options is compared in Sec. 4. Two other issues were also examined in this study: (1) the effect of alternative coal prices on the cost-effectiveness of regulatory options and (2) the comparative costs of firing a boiler with coal versus oil, which would affect the number of boilers subject to a regulatory option and, hence, the amount of SO_2 emission reduction overall that could be achieved. These two issues are discussed in Sec. 5. Study findings are presented in Sec. 6.

2 METHODOLOGY

2.1 ANALYSIS STEPS

The analysis of regulatory options for new industrial boilers was comprised of the following major components:

1. Developing a model to compute the cost of constructing a new industrial boiler with emissions controls,

2. Determining a regulatory baseline,

3. Comparing alternative regulatory options (emissions ceilings and mandatory percentage removal) based on their cost-effectiveness relative to the regulatory baseline,

4. Analyzing the sensitivity of model results to changes in (1) regulatory baseline assumptions, (2) the inclusion of CEM requirements, (3) provision for mixed-fuel and cogeneration credits, and (4) coal quality and cost data used for model runs, and

5. Examining projections of relative oil and coal prices, which would affect the proportion of future industrial boilers covered by the proposed NSPS revisions.

This section focuses primarily on describing the model that was developed. The other components of the analysis are described in later sections of this report.

2.2 MODEL DESCRIPTION

Industrial boiler SO_2 emissions and control costs for the NSPS regulatory options presented in this study were estimated with the use of the New Industrial Boiler (NIB) model, developed by ANL for this purpose. The NIB model computes the cost of meeting an SO_2 emission regulation for new coal-fired industrial boilers, based on regional fuel costs and a set of costs for SO_2 and PM control systems. Three control methods for complying with an SO_2 regulation are considered in the model: coal selection, coal cleaning, and installation of an FGD system. Coal selection options include one or more raw coals, one or more cleaned coals, or any combination of these coals. The NIB model selects one or any combination of these control methods (e.g., coal cleaning plus an FGD system) in order to arrive at the least-cost means of compliance. The control cost algorithms and other supporting information used in the NIB model are from EPA reports,[3,4] except as discussed in this section.

The model can be run for any boiler size. Depending on the size specified, the model automatically assigns a boiler type, i.e., stoker or pulverized. The boiler type may limit some of the FGD technology choices that can be considered for complying with regulatory options.

The cost and quality of raw coals available to a new industrial boiler are dependent on the location of the boiler relative to coal sources (on a regional basis). The model operates at the federal region level; Fig. 1 identifies these regions and their component states. For construction of the model, coal data provided by EPA were used to represent the average cost and quality of coals available to boilers in each federal region. The EPA coal data were developed by ICF for use in the Industrial Fuel Choice Analysis Model (IFCAM) model.[2]

However, because of the importance of coal costs to the model results, the final step of the methodology included a sensitivity run of the model using a second set of coal prices, covering one region in the East (Region 3), one in the Midwest (Region 5), and one in the West (Region 8). This second coal data set, which contains coal costs as a function of sulfur content, were derived from the Advanced Utility Simulation Model (AUSM)[5] by adjusting the output of the AUSM Coal Supply Module upward by 10%. (This increment of 10% approximated the cost difference between spot-market purchases and contract purchases.) These alternative cost data are lower than the EPA values, with the exception of very-low-sulfur coal in Region 3. Both coal data sets are presented in Sec. 5.

Based on the raw coal data included in the model, the model computes the cost of cleaning the coal. This is done by adjusting the cost and quality of the raw coals to reflect the effects of cleaned coals. Table 1 shows the changes in raw coal characteristics and costs that are used in the NIB model to simulate two levels of

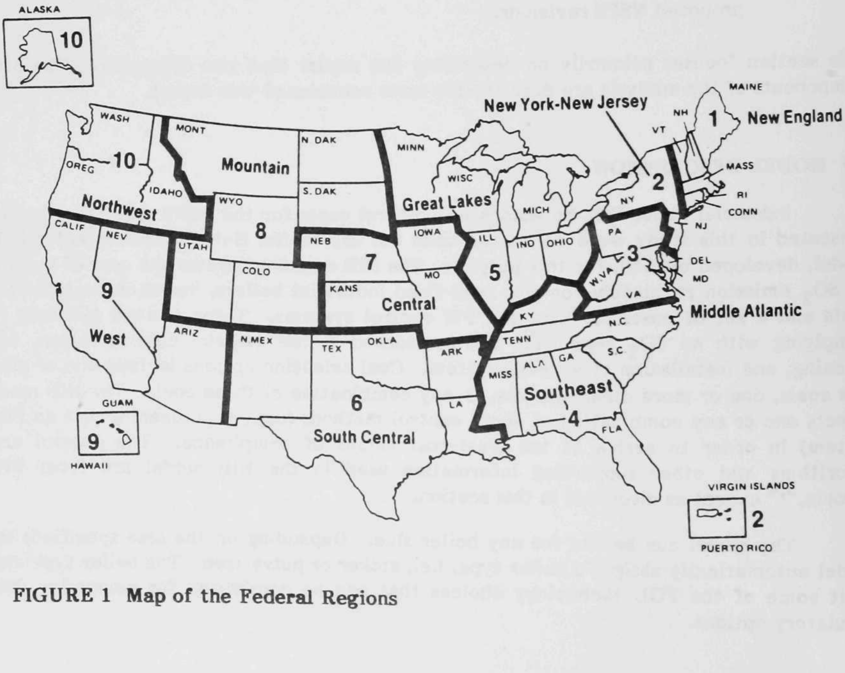

FIGURE 1 Map of the Federal Regions

TABLE 1 Cost and Effect on Coal Quality of Coal Cleaning

Cleaning Level, Coal Type	Raw Coal Sulfur Content ($lb\ SO_2/10^6$ Btu)	Effect of Coal Cleaning (% change) Ash Content	Heating Value	Sulfur Content	Cleaning Costs (1983 $\$/10^6$ Btu) Middle Value	Range
Level 1						
Bituminous	<1.08	-40	+6	-20	0.25	0.15-0.40
	1.08-1.67	-50	+6	-20	0.25	0.15-0.40
	1.68-2.50	-50	+8	-20	0.25	0.15-0.40
	2.51-3.33	-50	+8	-35	0.40	0.20-0.60
	3.34-5.00	-45	+8	-45	0.60	0.40-0.75
Subbituminous	<1.08	-10	+4	-20	0.25	0.15-0.40
	1.09-1.67	-10	+4	-20	0.25	0.15-0.40
	1.68-2.50	-10	+4	-20	0.25	0.15-0.40
Level 2: bituminous only	<1.08	-45	+7	-30	0.4	0.20-0.60
	1.08-1.67	-55	+7	-30	0.4	0.20-0.60
	1.69-2.50	-55	+9	-40	0.5	0.30-0.60
	2.51-3.33	-55	+9	-50	0.6	0.40-0.75
	3.34-5.00	-50	+9	-60	0.7	0.50-0.90

Source: Ref. 7.

physical cleaning. The amount of sulfur and ash removed from the coal and the increase in the coal heating value are dependent on the raw coal's sulfur content, coal type (bituminous or subbituminous), and level of cleaning. The coal cleaning characteristics and costs are based largely on a U.S. Department of the Interior report[6] and personal communication with D. Carter, U.S. Department of Energy (DOE).[7] The NIB model was run using the cleaned coal data with both sets of coal costs.

When scrubbing is not mandated by an SO_2 emission regulation, any two coals available in a region (including cleaned coals) can be blended to meet the emission limit specified by the regulation. For every coal and coal blend, SO_2 and particulate matter (PM) emissions are computed by the NIB model. Emissions of SO_2 are dependent on the coal's sulfur content and the amount of sulfur retained in the bottom ash of the boiler. Retention of SO_2 in boiler bottom ash is assumed in the model to be 5% for bituminous coal and 15% for subbituminous coal. It is also assumed that 100% of the sulfur emitted from an industrial boiler is in the form of SO_2.

For determination of compliance with an emission rate limit, all SO_2 emission regulations are based on a 30-day averaging time. To account for the sulfur variability in coal, the annual average SO_2 emission rate is adjusted such that it will not exceed the designated limit in any 30-day averaging period. This is accomplished in the model by multiplying annual average emission rates by a relative standard deviation factor. This factor is 1.1 and 1.2 for washed and raw coals, respectively. Annual emissions are based on annual average coal sulfur contents and not the peak values.

When coals are blended, the amount of sulfur retained in the bottom ash and coal sulfur variability are adjusted according to the proportional mix of coals in the blend. For example, when equal proportions (on a heat input basis) of cleaned and raw coals are blended together, the annual average sulfur content of the coal blend is increased by 15% for the computation of peak SO_2 emissions.

The NIB model determines that an FGD system must be installed when the SO_2 emission rate from the uncontrolled combustion of a coal is greater than the emission limit set by the regulation. The FGD options include four conventional control technologies: double alkali, sodium throwaway, lime/limestone wet scrubbing, and lime-spray drying. The NIB model computes capital and operation and maintenance (O&M) costs for each of these pollution control systems. Particulate matter control, when not included as part of the FGD system, is from a fabric filter system. The NIB model computes capital and O&M costs for installing and operating a fabric filter, reducing particulate emissions to 0.05 $lb/10^6$ Btu. Cost and performance algorithms for these technologies are based on EPA data.[4]

The total annualized costs for operating an FGD system include coal costs, levelized pollution control capital costs, O&M expenditures (fixed and variable), and monitoring costs for the FGD system. A 95% reliability is assumed for FGD systems, with natural gas combustion during outage periods. Total annualized costs for pollution control capital expenditures are based on a 10% real interest rate and a 15-year equipment lifetime. After total annualized costs are estimated for each coal and coal blend, the NIB model selects the least-cost fuel and FGD combination.

Two cost components that add substantially to the annual operating costs for FGD-controlled boilers are emissions monitoring and combustion of clean fuel (gas) during FGD outage. In the NIB model, boilers operating under the regulatory baseline are not required to install monitoring systems. This is standard practice under current regulations. Boilers under the revised NSPS (all options) are required to install and operate some form of CEM system. These annual costs are estimated in the model at \$110,000 for a non-FGD controlled boiler and \$143,000 for an FGD-controlled boiler.[4] The costs of switching to natural gas, when the FGD system is inoperable (5% of an annual operating period), are computed using EPA regional gas prices. This cost, of course, is not incurred by non-FGD-controlled boilers. These additional costs for operating an FGD-controlled boiler detract substantially from the attractiveness of selecting FGD systems to meet regulatory requirements.

The NIB model also estimates SO_2 control costs for industrial boilers that burn coal exclusively and for boilers that burn a mixture of coal and wood. The model also computes SO_2 control costs for coal-fired combined-cycle cogeneration boilers that derive a portion of their heat input from the exhaust of turbines firing distillate oil or natural gas. The emission credit is computed in a similar fashion for mixed-fuel and cogeneration boilers.

When an SO_2 credit is given, short-term peak SO_2 emissions are based on heat and sulfur contributions from (1) the combustion of both coal and wood for the mixed-fuels analysis, and (2) coal combustion together with exhaust gases for the cogeneration analysis. In this manner, peak SO_2 emission computations reflect the actual peak SO_2

emission rate leaving the stack. When credit is not given, short-term peak SO_2 emissions are based solely on the heat and sulfur inputs from the coal portion of the fuel inputs (for both the mixed-fuels and cogeneration analyses). Computing peak SO_2 emissions in this fashion tends to overestimate SO_2 emissions relative to actual emissions. A more detailed description of mixed-fuel and cogeneration credits is provided in Sec. 4.

In addition to computing boiler costs, fuel costs, and SO_2 control costs, the NIB model also compiles the cost of reducing PM emissions. Although it is assumed that under all regulatory scenarios a PM limit of 0.05 lb/10^6 Btu must be met, differences in the ash content among alternative coals may result in significantly lower or higher PM control costs.

3 SENSITIVITY OF COST-EFFECTIVENESS COMPUTATIONS TO THE REGULATORY BASELINE

Cost-effectiveness is used in this report as one of the key bases for comparing various regulatory options aimed at reducing SO_2 emissions from industrial boilers. The cost-effectiveness of any given option is defined as the difference in the cost per ton of SO_2 removed between that option and the regulatory baseline.* The latter refers to the emission rate and cost of operation for new coal-fired boilers under current regulations. At what emission rate the regulatory baseline is defined may therefore significantly influence the cost-effectiveness estimate for each regulatory option. This section explains the regulatory baseline that was selected for use in this study and examines the sensitivity of the NIB model results to different baseline assumptions.

3.1 REGULATORY BASELINE DETERMINATION

Two sources of information were used to determine an appropriate regulatory baseline for this study:

- The Prevention of Significant Deterioration/New Source Review (PSD/NSR) file compiled by Radian Corp. for EPA,[8] and
- The Best Available Control Technology/Lowest Achievable Emission Rate (BACT/LAER) clearinghouse data.[9]

The PSD/NSR file contains permit data for the period 1978-1984. There are two data sets in this file. The first consists of data collected through 1981 and was intended as a sample of preconstruction permits issued under EPA's post-1977 NSR regulations. This first data set was then supplemented and extended by Radian Corp. The resulting data set was intended as a comprehensive compilation of permits for the period January 1982 through December 1984. Thus, the second data set, which contains 155 entries, represents a more complete permitting record than the first. For each permit in the PSD/NSR file, both the size (in 10^6 Btu/h) and the SO_2 emission rate (in lb $SO_2/10^6$ Btu) of the facility are given.

The BACT/LAER file was abstracted from preconstruction permits submitted voluntarily by state and local pollution control agencies. The file reflects determinations made between January 1980 and January 1984. The data were screened to include only SO_2 determinations for external combustion boilers firing coal alone or in combination with other fuels. Only those determinations giving an SO_2 emission limit in lb/10^6 Btu were considered. Altogether, 142 determinations in the data base met these qualifications. From that group, a subset, containing 46 entries, was established

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*Cost-effectiveness of the alternative control strategy relative to the regulatory baseline is computed by dividing the increase in costs of meeting the more stringent emission limit by the decrease in SO_2 emissions.

consisting of those boilers for which the size is given in 10^6 Btu/h and the SO_2 emission rate in lb/10^6 Btu.

The emission limit established by existing NSPS regulations for boilers larger than 250 x 10^6 Btu/h is 1.2 lb $SO_2/10^6$ Btu. That this limit has been adhered to in the permitting process in each region is demonstrated in Table 2, which shows the number of large-boiler permits issued for each allowed emission level. Based on the large percentage of boilers permitted in the 1.0 to 1.4 lb $SO_2/10^6$ Btu range, a regulatory baseline of 1.2 lb $SO_2/10^6$ Btu for boilers larger than 250 x 10^6 Btu/h appears to be appropriate.

Determining a suitable baseline emission limit for boilers in the range of 100 to 250 x 10^6 Btu/h is a more difficult task. According to an EPA analysis in 1984, 28% of the boilers in this size range, permitted under PSD/NSR, have emission limits of greater than 2.0 lb $SO_2/10^6$ Btu.[10] Emission limits between 1.0 and 1.9 lb $SO_2/10^6$ Btu account for over 50% of the permits (based on Ref. 10). This information indicates that setting a single regulatory baseline above 2.0 lb $SO_2/10^6$ Btu for the entire nation would result in overestimates of emission reductions and underestimates of present operating expense. Therefore, a more detailed analysis of regional permit levels was conducted using the PSD/NSR and BACT/LAER data bases in order to establish a regulatory baseline for coal-fired boilers between 100 and 250 x 10^6 Btu/h that would account for the major differences among regions.

TABLE 2 Number of Permits in Each Region for >250 x 10^6 Btu/h Boilers, by SO_2 Emission Limit: BACT/LAER versus PSD/NSR Data Bases

	Permits under Each SO_2 Emission Limit (lb $SO_2/10^6$ Btu)											
	BACT/LAER Data Base						PSD/NSR Data Base					
Region	<0.6	0.6-1.0	1.0-1.4	1.4-2.0	2.0-3.0	>3.0	<0.6	0.6-1.0	1.0-1.4	1.4-2.0	2.0-3.0	>3.0
1, 2	0	0	2	0	0	0	2	1	3	0	0	0
3	0	1	0	0	0	0	0	0	0	0	0	0
4	2	1	5	0	0	0	3	8	21	0	0	0
5	1	1	2	2	0	0	1	0	2	0	0	0
6	3	1	1	0	0	0	3	2	10	0	0	0
7	1	0	0	0	0	0	0	0	0	0	0	0
8-10	2	0	0	0	0	0	4	0	1	0	0	0
Total	9	4	10	2	0	0	13	11	37	0	0	0

Source: Refs. 8 and 9.

The Radian permit compilation file was checked for completeness with all EPA regional offices and against the BACT/LAER file. The regional office files contained 38 permits for industrial boilers that were not in the Radian or BACT/LAER data bases, as follows: 1 each in Regions 6 and 8; 3 each in Regions 2, 4, and 9; 6 in Region 1; 8 in Region 5; and 13 in Region 3. Because of the significant number of permits issued in Regions 3 and 5 that are not in the PSD/NSR or BACT/LAER files, the emission limits specified in those permits were obtained. Based on that information, it was determined that the emission limits for boilers not in the two data files are similar to the limits that are contained in the data files.

Table 3 presents frequency distributions of recent BACT/LAER determinations and PSD/NSR permit levels for boilers between 100 and 250 x 10^6 Btu/h. For boilers in this size range, there are substantial differences in the emission limits between the data bases. In the PSD/NSR file, Regions 4 and 7 have the greatest number of permits for industrial boilers at or above 2.0 lb $SO_2/10^6$ Btu; about 15% of the total permits above 2.0 lb $SO_2/10^6$ Btu are for this size range of boilers. The BACT/LAER file shows only about 17% of the determinations for this boiler size to be above 2.0 lb $SO_2/10^6$ Btu in eastern regions.

TABLE 3 Number of Permits in Each Region for Boilers between 100 and 250 x 10^6 Btu/h, by SO_2 Emission Limit: BACT/LAER versus PSD/NSR Data Bases

	Permits under Each SO_2 Emission Limit (lb $SO_2/10^6$ Btu)											
	BACT/LAER Data Base						PSD/NSR Data Base					
Region	<0.6	0.6-1.0	1.0-1.4	1.4-2.0	2.0-3.0	>3.0	<0.6	0.6-1.0	1.0-1.4	1.4-2.0	2.0-3.0	>3.0
1, 2	1	1	0	2	0	0	0	0	0	1	0	0
3	0	1	1	0	1	1	0	1	0	0	1	0
4	1	0	2	4	1	0	0	1	4	4	2	3
5	0	0	0	0	0	0	0	1	12	13	1	0
6	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	1	0	0	0	0	0	3	4	0
8-10	0	0	0	0	0	0	3	0	0	0	0	0
Total	2	2	3	7	2	1	3	3	16	21	8	3

Source: Refs. 8 and 9.

Based on the data in Table 3, a distinction can be made between permitted SO_2 emission rates in eastern and western states. For the eastern regions (Regions 1-5 and 7), a value of 1.6 lb $SO_2/10^6$ Btu appears to be a reasonable baseline estimate, although this may be a slight underestimate for Region 7. For the western regions (Regions 6 and 8-10), there are few observations on which to base an estimate. However, based on the scant sample, a value of 1.2 lb $SO_2/10^6$ Btu appears to be a reasonable estimate of the regulatory baseline. This value should be considered as a conservative estimate since a fair amount of permitting in these regions is at 0.6 lb $SO_2/10^6$ Btu or below.

Further support for establishing the regulatory baseline for industrial boilers at levels below those in state implementation plans (SIPs) comes from the current PSD regulations. The SIP requirements for control technology review under PSD specify that new major stationary sources shall apply BACT for each pollutant (1) subject to regulation under the Clean Air Act and (2) that can be emitted by the source in significant amounts. Any stationary source that emits, or has the potential to emit, 250 tons/yr or more of any pollutant subject to regulation under the act is subject to review. Also, fossil-fuel-fired boilers with a combined heat input capacity of greater than 250 x 10^6 Btu/h and that emits, or has the potential to emit, 100 tons/yr of any pollutant subject to regulation under the act are, by definition, major stationary sources. Finally, a major stationary source is subject to control technology review if it emits, or has the potential to emit, equal or greater than 40 tons/yr of SO_2. This 40-ton/yr limit causes even small boilers to be subject to a BACT review. Although the BACT review results in a range of control type and emission rates, it seldom results in allowed emissions that exceed 2.0 lb $SO_2/10^6$ Btu. For states with high SIP limits, the permit level is generally well below the SIP limit.

3.2 SENSITIVITY ANALYSIS

This section presents a sensitivity analysis of regulatory option cost-effectiveness as a function of the regulatory baseline. Cost-effectiveness estimates were calculated using the NIB model for a range of baselines. The results are summarized in Tables 4 and 5 for four baselines and two regions (Regions 5 and 8).

For Region 5 (see Table 4), the cost-effectiveness estimates differ significantly between the maximum regulatory baseline considered of 2.5 lb $SO_2/10^6$ Btu and the baseline established for use in this study. For 100 and 250 x 10^6 Btu/h boilers, the differences range from \$650/ton to \$1,270/ton. For 400 x 10^6 Btu/h boilers, the differences range from \$400 to in excess of \$600/ton, depending on the regulatory option. In Region 8 (see Table 5), the differences in cost-effectiveness between the 2.5 and 1.2 lb $SO_2/10^6$ Btu baselines generally decrease with increasing boiler size for each regulatory option. The smallest differences in cost-effectiveness are for the mandatory percentage removal options.

Figure 2 presents the cost-effectiveness of meeting the utility NSPS regulatory option for boilers located in Regions 5 and 8. The figure illustrates the importance of the baseline definition for all boilers, but especially small boilers. For 100 x 10^6 Btu/h boilers in Region 5, the difference in the cost-effectiveness estimate is \$1365/ton. This difference reduces to \$822/ton for 250 x 10^6 Btu/h boilers in the same region. The

TABLE 4 Effect of Different Regulatory Baselines on the Cost-Effectiveness of Meeting Selected Regulatory Options: Region 5

Boiler Size,[a] Regulatory Option	Cost-Effectiveness Options by Regulatory Baseline ($lb\ SO_2/10^6$ Btu)				Differences in Cost-Effectiveness between the Highest Baseline Considered and the ANL Baseline[b,c]
	2.5	2.0	1.6[b]	1.2[c]	
100 x 10^6 Btu/h					
Emission ceilings					
1.2 lb $SO_2/10^6$ Btu	816	1126	1933	-[d]	1117
0.8 lb $SO_2/10^6$ Btu	926	1191	1661	2811	735
0.6 lb $SO_2/10^6$ Btu	1213	1532	2017	2910	804
1979 Utility NSPS	1169	1451	1861	2534	692
Mandatory 90% removal[e]	1207	1502	1931	2645	724
250 x 10^6 Btu/h					
Emission ceilings					
1.2 lb $SO_2/10^6$ Btu	599	760	1178	-[d]	-[d]
0.8 lb $SO_2/10^6$ Btu	779	970	1308	2047	1268
0.6 lb $SO_2/10^6$ Btu	824	996	1258	1646	822
1979 Utility NSPS	824	996	1258	1646	822
Mandatory 90% removal[e]	797	949	1169	1450	653
400 x 10^6 Btu/h					
Emission ceilings					
1.2 lb $SO_2/10^6$ Btu	549	671	561	-[d]	-[d]
0.8 lb $SO_2/10^6$ Btu	643	763	968	1263	620
0.6 lb $SO_2/10^6$ Btu	627	724	872	1005	378
1979 Utility NSPS	643	752	922	1107	464
Mandatory 90% removal[e]	643	752	922	1107	464

[a]Annual capacity factor is 0.6.

[b]The ANL baseline for ≥100 and <250 x 10^6 Btu/h boilers in Region 5 is 1.6 lb $SO_2/10^6$ Btu.

[c]The ANL baseline for ≥250 x 10^6 Btu/h boilers in Region 5 is 1.2 lb $SO_2/10^6$ Btu.

[d]The regulatory option is the same as the regulatory baseline; hence, there is no difference in cost or cost-effectiveness.

[e]Mandatory 90% removal with a 0.8 lb $SO_2/10^6$ Btu emission ceiling.

TABLE 5 Effect of Different Regulatory Baselines on the Cost-Effectiveness of Meeting Selected Regulatory Options: Region 8

Boiler Size,[a] Regulatory Option	Cost-Effectiveness Options by Regulatory Baseline ($lb\ SO_2/10^6$ Btu) 2.5	2.0	1.6	1.2[b]	Differences in Cost-Effectiveness between the Highest Baseline Considered and the ANL Baseline[b]
100 x 10^6 Btu/h					
Emission ceilings					
1.2 lb $SO_2/10^6$ Btu	765	847	1475	-[c]	-[c]
0.8 lb $SO_2/10^6$ Btu	814	875	1219	2320	1506
0.6 lb $SO_2/10^6$ Btu	1431	1535	2061	3290	1859
1979 Utility NSPS	1286	1364	1727	2431	1145
Mandatory 90% removal[d]	1186	1248	1525	2005	819
250 x 10^6 Btu/h					
Emission ceilings					
1.2 lb $SO_2/10^6$ Btu	463	496	747	-[c]	-[c]
0.8 lb $SO_2/10^6$ Btu	635	675	901	1625	990
0.6 lb $SO_2/10^6$ Btu	999	1064	1391	2156	1157
1979 Utility NSPS	910	958	1185	1624	714
Mandatory 90% removal[d]	848	887	1060	1360	512
400 x 10^6 Btu/h					
Emission ceilings					
1.2 lb $SO_2/10^6$ Btu	384	405	561	-[c]	-[c]
0.8 lb $SO_2/10^6$ Btu	583	618	812	1433	850
0.6 lb $SO_2/10^6$ Btu	857	909	1174	1791	934
1979 Utility NSPS	904	961	1246	1912	1008
Mandatory 90% removal[d]	737	768	909	1152	415

[a]Annual capacity factor is 0.6.

[b]The ANL baseline for all boiler sizes in Region 8 is 1.2 lb $SO_2/10^6$ Btu.

[c]The regulatory option is the same as the regulatory baseline; hence, there is no difference in cost or cost-effectiveness.

[d]Mandatory 90% removal with a 0.8 lb $SO_2/10^6$ Btu emission ceiling.

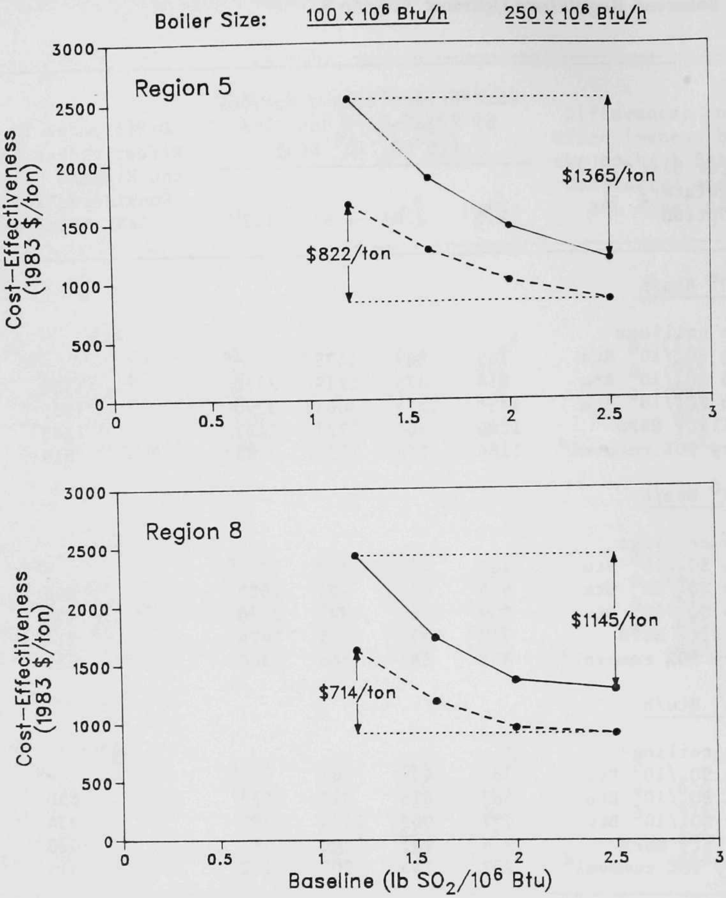


FIGURE 2 Effect of Different Regulatory Baselines on the Cost-Effectiveness of Complying with 1979 Utility NSPS, by Boiler Size

differences are marginal for boilers between 100 and 250 x 10^6 Btu/h in Region 8 (versus Region 5).

Several conclusions can be drawn from this evaluation of regulatory baselines and their effect on the cost-effectiveness of complying with various regulatory options. These conclusions are summarized below:

- Cost-effectiveness estimates for several regulatory options relative to a range of baseline values from 2.5 through 1.2 lb $SO_2/10^6$ Btu indicate that selection of a regulatory baseline in this range can yield a $1,000/ton difference in cost-effectiveness for small boilers in western regions.

- A reasonable estimate of the regulatory baseline for boilers larger than 250 x 10^6 Btu/h heat input is 1.2 lb $SO_2/10^6$ Btu.

- Emission limits for boilers between 100 and 250 x 10^6 Btu/h exhibit some regional differences. A reasonable estimate of the regulatory baseline in the eastern United States (Regions 1-5 and 7) would be 1.6 lb $SO_2/10^6$ Btu. In the western United States (Regions 6 and 8-10) a baseline value of 1.2 lb $SO_2/10^6$ Btu appears to be a conservative estimate.

- In addition to minimizing the cost-effectiveness of regulatory options, use of a 2.5 lb $SO_2/10^6$ Btu baseline exaggerates national SO_2 emission reductions. However, these changes cannot be estimated from the national summary information presented in EPA analyses.[2]

4 REGULATORY OPTIONS

As discussed in Sec. 3, a reasonable estimate of the emission rate under current regulations was determined to be 1.2 lb $SO_2/10^6$ Btu for boilers equal to or greater than 250 x 10^6 Btu/h in all federal regions. For boilers greater than 100 and less than 250 x 10^6 Btu/h, the estimate considered reasonable was 1.6 lb $SO_2/10^6$ Btu in Regions 1-5 and 7, and 1.2 lb $SO_2/10^6$ Btu in all other regions. These emission rates were therefore adopted as the regulatory baseline for use in evaluating the cost-effectiveness of various regulatory options.

4.1 EMISSION CEILINGS AND MANDATORY PERCENTAGE REMOVAL REQUIREMENTS

The regulatory options that were evaluated against the regulatory baseline, using the NIB model, were as follows:

1. *Emission ceilings ranging from 0.2 to 1.6 lb $SO_2/10^6$ Btu.* These ceilings were used to establish "break points," where meeting the requirement would cause a substantial incremental cost increase.

2. *1979 utility NSPS.* This option would involve application of the sliding-scale NSPS for utility boilers to industrial boilers.

3. *A 0.8 lb $SO_2/10^6$ Btu ceiling combined with a 90% mandatory removal requirement.* This combined regulatory option would allow the operator to select from almost all coals.

4. *A 0.8 lb $SO_2/10^6$ Btu ceiling combined with a 70% mandatory removal requirement.* This combined regulatory option would still allow adequate coal selection options. (In contrast, for example, a ceiling of 0.6 lb $SO_2/10^6$ Btu would limit coal selection to low-sulfur coals.) This combined option leaves an opportunity to use technologies achieving moderate removal (e.g., lime-spray drying) on medium- and low-sulfur coals.

These options were selected to provide data across a range of potentially viable options. Other regulatory options were also considered in the modeling, but they provided no additional insight relative to those listed above.

For each regulatory option, the NIB model was run for 100, 250, and 400 x 10^6 Btu/h coal-fired boilers in each of the 10 federal regions with annual capacity factors of 0.6 and 0.4. The results summarized in this report are for boilers in Regions 3, 5, and 8, operating at a capacity factor of 0.6, unless otherwise indicated. These three regions were chosen to represent three broad sections of the country.

The discussion concentrates on Regions 5 and 8, since the results for Region 3 are generally similar to those for Region 5. Two sets of runs were performed, the first using EPA coal costs, which is reported in this section. In a later stage of the analysis, the sensitivity of the results to different coal costs was tested by using coal costs derived from the AUSM. Those results are discussed in Sec. 5.

The NIB model uses EPA cost algorithms for two boiler types (stoker and pulverized coal) and four control technologies: lime-spray drying, dual alkali, sodium throwaway, and lime/limestone wet scrubbers. The model selects the least-cost combination of one of these control technologies and an available coal that meets the requirements of the regulatory option. The characteristics of the available coals can be modified to reflect physical coal cleaning, allowing another means for meeting the regulatory limit.

Before the results are discussed, it is important to stress that, although these combinations represent a large number of options, the model must be viewed as a simplistic representation of a very complex environment. Some combustion and control technologies that are being selected for boilers in utility capacity expansion plans are not contained in the NIB model. Atmospheric fluidized bed combustion is a prime example of a proven combustion technology being selected for some new boilers. Emerging control technologies that offer such desirable features as reduced operating costs and smaller secondary environmental impacts need to be qualitatively factored into any analysis of the modeling results. Making important decisions based on a single indicator (i.e., cost-effectiveness) computed by a simplistic model can be misleading.

Table 6 presents the NIB model results, based on EPA coal costs, for boilers meeting a range of emission ceilings: 1.4, 1.2, 1.0, 0.8, and 0.6 lb $SO_2/10^6$ Btu. Based on these results, several observations can be made:

- The most cost-effective emission ceiling for 100 x 10^6 Btu/h boilers in all three regions is 0.8 lb $SO_2/10^6$ Btu, which is achieved by burning cleaned coal. However, the cost-effectiveness values still far exceed $1,000/ton, with the minimum being $1,661/ton in Region 5.

- Higher emission ceilings (1.2 and 1.0 lb $SO_2/10^6$ Btu) are achieved by switching to a compliance coal. The cost increase for these cases is largely attributable to incremental fuel costs and emission monitoring costs.

- Only in Region 3, where the 400 x 10^6 Btu/h boiler operates a scrubber on high-sulfur local coal at the regulatory baseline, does the cost-effectiveness fall below $1,000/ton for any of the emission ceilings.

Table 7 presents the NIB model results, based on EPA coal costs, for the mandatory percentage removal regulatory options. The results cover fuel and FGD selection, annualized costs, and emissions. Key observations based on the table are as follows:

TABLE 6 NIB Model Results for Emission Ceiling Regulatory Options in Regions 3, 5, and 8: Least-Cost Compliance Method, Emissions, Annualized Cost, and Cost-Effectiveness

	0.6 Capacity Factor					0.4 Capacity Factor				
Region, Boiler Size (10^6 Btu/h)	Coal (% S)	Control Method, % Removal[a]	Emissions (tons/yr)	Annualized Cost (1983 $\$10^3$/yr)	CE[b] ($/ton)	Coal (% S)	Control Method, % Removal[a]	Emissions (tons/yr)	Annualized Cost (1983 $\$10^3$/yr)	CE[b] ($/ton)
	ANL Regulatory Baseline									
Region 3										
100	0.89	-	350	4,212	-	0.89	-	234	3,420	-
250	0.67	-	657	10,219	-	0.74	-	465	8,239	-
400	2.59	dry	1,051	14,953	-	0.74	-	745	11,946	-
Region 5										
100	0.88	-	350	4,344	-	0.88	-	234	3,510	-
250	0.66	-	657	10,483	-	0.66	-	438	8,432	-
400	0.66	-	1,051	15,386	-	0.66	-	701	12,234	-
Region 8										
100	0.51	-	263	3,592	-	0.51	-	175	3,075	-
250	0.51	-	657	8,184	-	0.51	-	438	6,986	-
400	0.51	-	1,051	11,632	-	0.51	-	701	9,828	-
	1.4 lb $SO_2/10^6$ Btu Ceiling									
Region 3										
100	0.82	-	314	4,359	4,073	0.82	-	209	3,551	5,459
250	0.78	-	767	10,219	-5	0.82	-	524	8,283	-770
400	0.78	-	1,226	14,902	288	0.82	-	838	11,943	38
Region 5										
100	0.77	-	307	4,483	3,162	0.77	-	204	3,639	4,419
250	0.77	-	767	10,516	-305	0.77	-	511	8,491	-803
400	0.77	-	1,226	15,374	71	0.77	-	818	12,262	-241
Region 8										
100	0.60	-	307	3,692	-2,293	0.60	-	204	3,179	-3,569
250	0.60	-	767	8,277	-760	0.60	-	511	7,078	-1,270
400	0.60	-	1,226	11,698	-380	0.60	-	818	9,909	-700

TABLE 6 (Cont'd)

Region, Boiler Size (10^6 Btu/h)	0.6 Capacity Factor: Coal (% S)	Control Method, % Removal[a]	Emissions (tons/yr)	Annualized Cost (1983 $\$10^3$/yr)	CE[b] ($/ton)	0.4 Capacity Factor: Coal (% S)	Control Method, % Removal[a]	Emissions (tons/yr)	Annualized Cost (1983 $\$10^3$/yr)	CE[b] ($/ton)
				1.2 lb $SO_2/10^6$ Btu Ceiling						
Region 3										
100	0.74	-	279	4,398	2,623	0.74	-	186	3,574	3,248
250	0.67	-	657	10,329	-	0.74	-	466	8,349	-
400	0.67	-	1,051	15,077	-	0.74	-	745	12,056	-
Region 5										
100	0.66	-	263	4,513	1,933	0.66	-	175	3,660	2,564
250	0.66	-	657	10,593	-	0.66	-	438	8,542	-
400	0.66	-	1,051	15,496	-	0.66	-	701	12,344	-
Region 8										
100	0.51	-	263	3,702	-	0.51	-	175	3,184	-
250	0.51	-	657	8,304	-	0.51	-	438	7,096	-
400	0.51	-	657	11,742	-	0.51	-	701	9,938	-
				1.0 lb $SO_2/10^6$ Btu Ceiling						
Region 3										
100	0.64	-	239	4,448	2,116	0.64	-	159	3,605	2,486
250	0.64	-	597	10,460	4,035	0.64	-	398	8,432	2,859
400	0.64	dry, 78	876	15,159	1,180	0.64	-	637	12,194	2,295
Region 5										
100	0.57	-	223	4,556	1,659	0.57	-	148	3,686	2,066
250	0.57	-	557	10,705	2,221	0.57	-	371	8,613	2,711
400	0.57	-	891	15,681	1,839	0.57	-	594	12,463	2,139
Region 8										
100	0.43	-	219	3,711	2,730	0.43	-	146	3,190	3,965
250	0.43	-	548	8,331	1,249	0.43	-	365	7,113	1,744
400	0.43	-	876	11,785	875	0.43	-	584	9,966	1,184

TABLE 6 (Cont'd)

Region, Boiler Size (10^6 Btu/h)	0.6 Capacity Factor: Coal (% S)	Control Method, % Removal[a]	Emissions (tons/yr)	Annualized Cost (10^3/yr) (1983 $)	CE[b] ($/ton)	0.4 Capacity Factor: Coal (% S)	Control Method, % Removal[a]	Emissions (tons/yr)	Annualized Cost (10^3/yr) (1983 $)	CE[b] ($/ton)
0.8 lb $SO_2/10^6$ Btu Ceiling										
Region 3										
100	0.51	PCC	191	4,513	1,888	0.51	PCC	127	3,649	2,152
250	2.59	sodm, 83	438	10,595	1,717	0.51	PCC	319	8,540	2,043
400	2.59	dry, 83	701	15,235	806	2.59	dry, 83	467	12,281	1,205
Region 5										
100	0.49	PCC	188	4,614	1,661	0.49	PCC	125	3,719	1,929
250	0.49	PCC	470	10,866	2,047	0.49	PCC	313	8,710	2,226
400	3.23	dry, 87	701	15,828	1,263	0.49	PCC	501	12,631	1,984
Region 8										
100	0.37	PCC	183	3,776	2,320	0.37	PCC	122	3,229	2,911
250	0.37	PCC	458	8,517	1,625	0.37	PCC	305	7,233	1,867
400	0.37	PCC	733	12,088	1,433	0.37	PCC	489	10,162	1,579
0.6 lb $SO_2/10^6$ Btu Ceiling										
Region 3										
100	2.59	sodm, 87	131	4,628	1,900	2.59	sodm, 87	87	3,815	2,707
250	2.59	sodm, 87	329	10,628	1,245	2.59	sodm, 87	219	8,678	1,781
400	2.59	dry, 87	526	15,330	717	2.59	sodm, 87	350	12,349	1,021
Region 5										
100	0.87	sodm, 61	131	4,786	2,017	0.87	sodm, 61	88	3,907	2,723
250	2.38	sodm, 87	329	11,023	1,646	0.87	sodm, 61	219	8,942	2,330
400	3.23	dual, 90	526	15,914	1,005	2.38	dry, 87	350	12,785	1,572
Region 8										
100	0.42	sodm, 38	131	4,024	3,290	0.42	sodm, 38	88	3,462	4,423
250	0.42	sodm, 38	329	8,902	2,156	0.42	sodm, 38	219	7,583	2,725
400	0.42	sodm, 38	526	12,573	1,791	0.42	sodm, 38	350	10,599	2,202

[a] Control method abbreviations: dry = lime-spray drying, dual = dual alkali, sodm = sodium throwaway, and PCC = partially cleaned coal. Where applicable, the percentage removal is also included.

[b] Cost effectiveness = (regulatory option cost − baseline cost)/(baseline emissions − regulatory option emissions).

TABLE 7 NIB Model Results for Mandatory Percentage Removal Options in Regions 3, 5, and 8: Least-Cost Compliance Method, Emissions, Annualized Cost, and Cost-Effectiveness

Region, Boiler Size (10^6 Btu/h)	0.6 Capacity Factor: Coal (% S)	Control Method, % Removal[a]	Emissions (tons/yr)	Annualized Cost (1983 $$10^3$/yr)	CE[b] ($/ton)	0.4 Capacity Factor: Coal (% S)	Control Method, % Removal[a]	Emissions (tons/yr)	Annualized Cost (1983 $$10^3$/yr)	CE[b] ($/ton)
ANL Regulatory Baseline										
Region 3										
100	0.89	-	350	4,212	-	0.89	-	234	3,420	-
250	0.67	-	657	10,219	-	0.74	-	465	8,239	-
400	2.59	dry	1,051	14,953	-	0.74	-	745	11,946	-
Region 5										
100	0.88	-	350	4,344	-	0.88	-	234	3,510	-
250	0.66	-	657	10,483	-	0.66	-	438	8,432	-
400	0.66	-	1,051	15,386	-	0.66	-	701	12,234	-
Region 8										
100	0.51	-	263	3,592	-	0.51	-	175	3,075	-
250	0.51	-	657	8,184	-	0.51	-	438	6,986	-
400	0.51	-	1,051	11,632	-	0.51	-	701	9,828	-
1979 Utility NSPS										
Region 3										
100	2.59	sodm, 87	131	4,628	1,900	2.59	sodm, 87	88	3,815	2,707
250	2.59	sodm, 87	329	10,628	1,245	2.59	sodm, 87	219	8,678	1,781
400	2.59	dry, 87	526	15,330	717	2.59	dry, 87	350	12,349	1,021
Region 5										
100	0.80	sodm, 68	109	4,794	1,861	0.87	sodm, 68	73	3,913	2,505
250	2.38	sodm, 87	329	11,023	1,646	0.87	sodm, 68	181	8,956	2,039
400	3.23	dual, 89	582	15,905	1,107	3.23	dry, 89	388	12,776	1,734
Region 8										
100	0.42	sodm, 64	75	4,048	2,431	0.42	sodm, 64	50	3,481	3,243
250	0.42	sodm, 64	187	8,957	1,624	0.42	sodm, 64	125	7,622	2,034
400	0.90	dry, 71	526	12,637	1,912	0.90	dry, 71	350	10,605	2,217

TABLE 7 (Cont'd)

Region, Boiler Size (10^6 Btu/h)	0.6 Capacity Factor: Coal (% S)	Control Method, % Removal[a]	Emissions (tons/yr)	Annualized Cost (10^3/yr, 1983 $)	CE[b] ($/ton)	0.4 Capacity Factor: Coal (% S)	Control Method, % Removal[a]	Emissions (tons/yr)	Annualized Cost (10^3/yr, 1983 $)	CE[b] ($/ton)
90% Removal with a 0.8 lb $SO_2/10^6$ Btu Ceiling[c]										
Region 3										
100	2.59	sodm	109	4,635	1,753	2.59	sodm	73	3,820	2,487
250	2.59	sodm	273	10,644	1,108	2.59	sodm	182	8,690	1,588
400	2.59	dry	436	15,390	711	2.59	dry	291	12,392	981
Region 5										
100	2.38	sodm	109	4,810	1,931	0.87	sodm	24	3,932	2,015
250	2.38	sodm	273	11,040	1,450	1.29	sodm	243	8,972	2,764
400	3.23	dual	582	15,905	1,107	3.23	dry	338	12,776	1,734
Region 8										
100	0.42	sodm	25	4,069	2,005	0.42	sodm	17	3,496	2,657
250	0.42	sodm	62	9,003	1,360	0.42	sodm	42	7,656	1,690
400	0.42	sodm	100	12,728	1,152	0.42	sodm	67	10,710	1,391
70% Removal with a 0.8 lb $SO_2/10^6$ Btu Ceiling[c]										
Region 3										
100	2.59	sodm, 83	175	4,615	2,297	2.59	sodm, 83	117	3,806	3,301
250	2.59	sodm, 83	438	10,595	1,717	2.59	dry, 83	292	8,651	2,373
400	2.59	dry, 83	701	15,235	806	2.59	dry, 83	467	12,281	1,205
Region 5										
100	2.38	sodm, 83	175	4,789	2,542	0.87	sodm, 68	73	3,913	2,505
250	2.38	sodm, 83	438	10,990	2,319	2.38	dry, 83	292	8,941	3,485
400	3.23	dry, 87	701	15,828	1,263	2.38	dry, 83	467	12,717	2,066
Region 8										
100	0.42	sodm, 64	75	4,048	2,431	0.42	sodm, 64	50	3,481	3,243
250	0.42	sodm, 64	187	8,957	1,624	0.90	dry, 64	273	7,620	3,850
400	0.90	dry, 64	656	12,593	2,430	0.90	dry, 64	437	10,572	2,822

[a]Control method abbreviations: dry = lime-spray drying, dual = dual alkali, sodm = sodium throwaway, and PCC = partially cleaned coal. Where applicable, the percentage removal is also included.

[b]Cost effectiveness = (regulatory option cost - baseline cost)/(baseline emissions - regulatory option emissions).

[c]Another, similar option tested, 90% removal with a 0.6 lb $SO_2/10^6$ Btu ceiling, produced identical results in Regions 3 and 8. Small differences in CE in Region 5 were predicted due to removing slightly more sulfur to reach the lower ceiling.

- The only boilers that achieve a cost-effectiveness of less than \$1,000/ton for any of the mandatory percentage removal regulatory options are 400 x 10^6 Btu/h boilers in Region 3.

- The average cost-effectiveness for 100 x 10^6 Btu/h boilers in Region 8 (at a 0.6 capacity factor) does not drop below \$2,000/ton for the mandatory percentage removal regulatory options.

Based on this information, it appears that determining an NSPS level, particularly for small and medium-sized boilers, while maintaining reasonable cost-effectiveness (e.g., below \$1,000/ton), will be difficult.

The cost increases and cost-effectiveness associated with a range of regulatory options were plotted for 100 and 400 x 10^6 Btu/h boilers in Regions 3, 5, and 8. The capacity factor used in all cases was 0.6. The emission limits considered were 0.2 lb $SO_2/10^6$ Btu and all 0.1 lb increments from (and including) 0.4 lb $SO_2/10^6$ Btu through 1.6 lb $SO_2/10^6$ Btu.

Figure 3 presents the cost increase and cost-effectiveness for each of the emission ceilings and the mandatory percentage removal regulatory options for a 100 x 10^6 Btu/h boiler in Region 3. The cost increase for boilers operating at 1.6 lb $SO_2/10^6$ Btu, which is the regulatory baseline for this boiler size, consists of the additional monitoring costs proposed by EPA. The figure also indicates the least-cost method selected by the model for complying with each emission limit: that is, combustion of compliance and/or cleaned coal blends or installation of an FGD system. The slope of the cost-effectiveness curve is large between the 1.5 and 1.1 lb $SO_2/10^6$ Btu emission ceilings, but reduces to almost zero between the 1.0 and 0.2 lb $SO_2/10^6$ Btu ceilings. For each level of SO_2 reduction, the costs of the mandatory percentage removal options are higher than or equal to the costs of emission ceiling options.

This pattern is repeated for the same size of boilers in Region 5 (see Fig. 4), with minimal change in cost-effectiveness among the regulatory options within the range where cleaned coal is selected as the means of compliance. The decrease in cost-effectiveness between the 0.6 and 0.2 lb $SO_2/10^6$ Btu emission ceilings is due to the operation of a scrubber system at higher efficiencies. As in Region 3, for each level of SO_2 reduction, the cost-effectiveness of the mandatory percentage removal options is higher than or equal to the cost-effectiveness of the emission ceiling options.

The same pattern described for Regions 3 and 5 is repeated, but exaggerated, for 100 x 10^6 Btu/h boilers in Region 8 (see Fig. 5). In general, cost-effectiveness estimates are more than \$1,000/ton higher than they are in Region 5. Relative to the emissions change, there is a substantial cost increment between 0.7 and 0.6 lb $SO_2/10^6$ Btu. This increment represents the costs of burning a cleaned coal compared to operating a scrubber system. The increment in annualized cost between meeting a 0.7 and 0.6 lb $SO_2/10^6$ Btu ceiling is about \$210,000, with an emission reduction of only 35 tons/yr. This cost versus emissions change tradeoff yields an incremental cost-effectiveness of

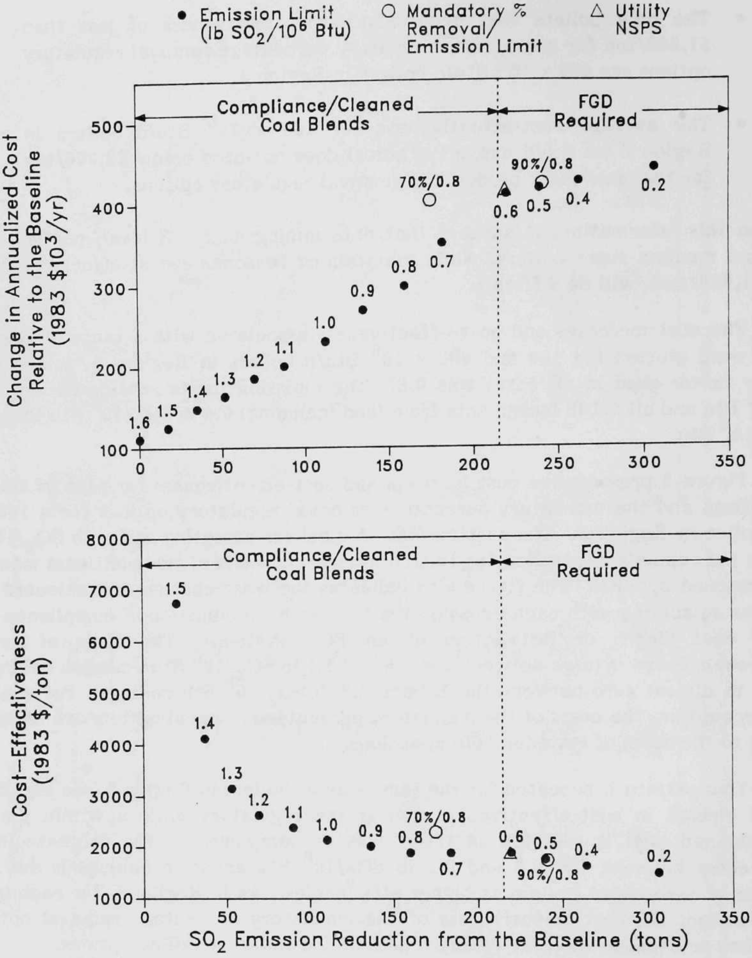


FIGURE 3 SO_2 Emission Reductions Corresponding with Various Emission Ceilings: Cost-Effectiveness and Changes in Annualized Cost for 100 x 10^6 Btu/h Boilers, Region 3

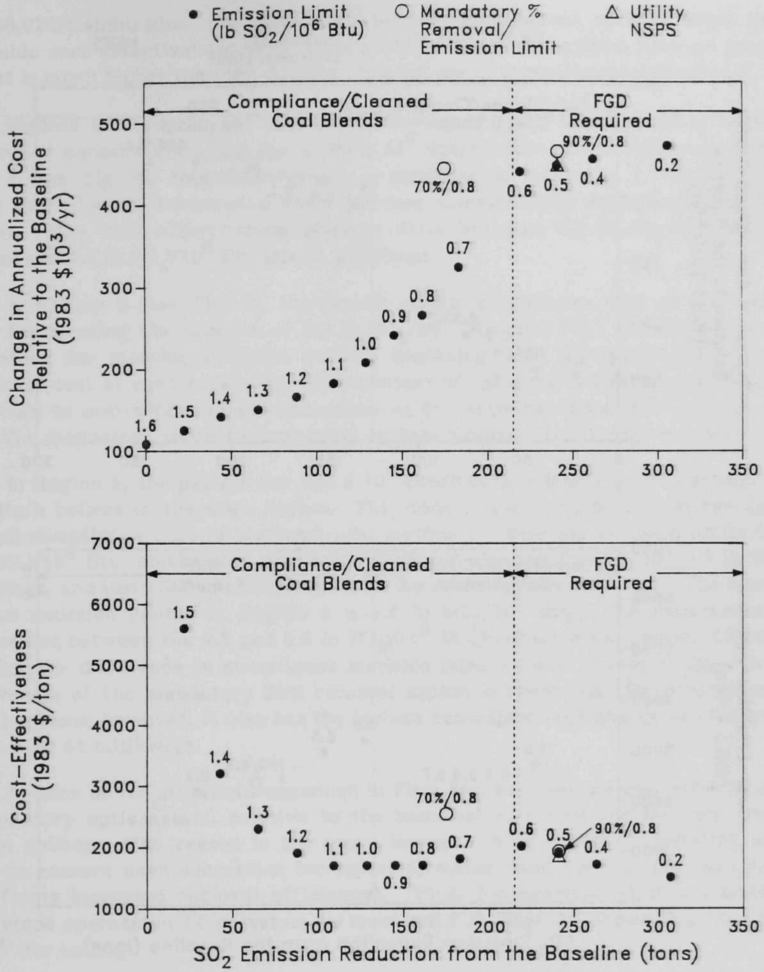


FIGURE 4 SO_2 Emission Reductions Corresponding with Various Emission Ceilings: Cost-Effectiveness and Changes in Annualized Cost for 100 x 10^6 Btu/h Boilers, Region 5

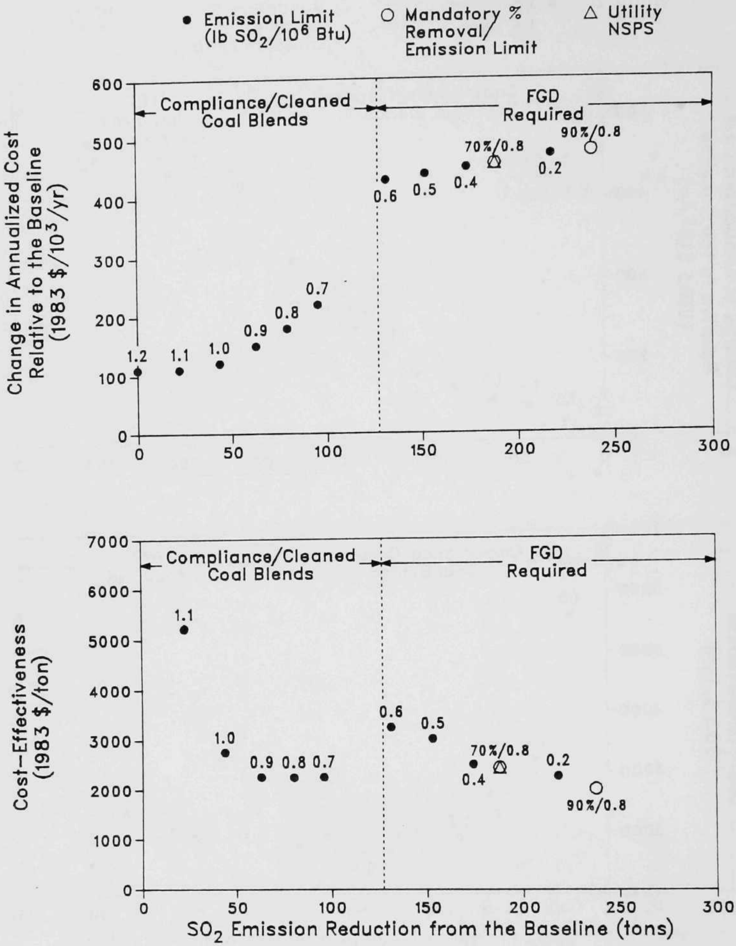


FIGURE 5 SO_2 Emission Reductions Corresponding with Various Emission Ceilings: Cost-Effectiveness and Changes in Annualized Cost for 100 x 10^6 Btu/h Boilers, Region 8

about \$6,028/ton.* Also, the mandatory percentage removal options, while showing comparable cost-effectiveness with the low emission ceiling options, have an annualized cost that is much higher than the options allowing use of compliance/cleaned coal.

Figures 6-8 present the change in annualized costs and cost-effectiveness for each level of emission reduction for a 400 x 10^6 Btu/h boiler at a 0.6 capacity factor. In Region 3 (see Fig. 6), the model selects a scrubber to meet the 1.2 lb $SO_2/10^6$ Btu baseline limit; hence, incremental costs increase monotonically while cost-effectiveness decreases. The cost-effectiveness changes little between 0.8 lb $SO_2/10^6$ Btu (about \$750/ton) and 0.2 lb $SO_2/10^6$ Btu (about \$620/ton).

In Region 5 (see Fig. 7), the model selects compliance coal as the least-cost method for meeting the baseline of 1.2 lb $SO_2/10^6$ Btu, and FGD systems as the least-cost method for meeting emission ceilings beginning with 0.9 lb $SO_2/10^6$ Btu. The incremental cost of each regulatory option tapers off at about 0.7 lb $SO_2/10^6$ Btu, which corresponds to cost-effectiveness reductions at the extreme end of the emission ceiling range. The mandatory percentage removal options produce comparable results.

In Region 8, the pattern for 400 x 10^6 Btu/h boilers (see Fig. 8) is similar to 100 x 10^6 Btu/h boilers in the same region. The model selects combustion of raw (perhaps screened) compliance coal as the least-cost method for meeting emission limits through 0.9 lb $SO_2/10^6$ Btu, combustion of cleaned coal for meeting the 0.8 and 0.7 lb $SO_2/10^6$ Btu ceilings, and installation of FGD systems for meeting lower ceilings. The most cost-effective emission ceiling in Region 8 is 1.0 lb $SO_2/10^6$ Btu. The incremental cost-effectiveness between the 0.7 and 0.6 lb $SO_2/10^6$ Btu ceilings is substantial (\$2,247/ton), reflecting the difference in compliance methods (cleaned coal versus FGD). The cost-effectiveness of the mandatory 90% removal option is lower than for other mandatory removal options; however, it also has the highest annualized cost charge of all regulatory options, over \$1 million/yr.

In each of the situations examined in Figs. 3-8, the average cost-effectiveness of the regulatory options (i.e., relative to the baseline) was least for the most stringent emission ceiling. The reason is the small increase in the cost of operating an FGD system to remove each successive increment of sulfur from the flue gas (i.e., the cost only reflects increased removal efficiency). Thus, for example, it is not much more expensive to operate an FGD system to meet a 0.2 lb $SO_2/10^6$ Btu ceiling than a 0.6 lb $SO_2/10^6$ Btu ceiling.

Other trends in the data are also of interest, particularly as they relate to emission ceilings between 0.7 and 0.9 lb $SO_2/10^6$ Btu. For 100 x 10^6 Btu/h boilers, cleaned coal is the least-cost option in all three regions for emission ceilings in this range. However, although the cost-effectiveness of meeting these emission limits is higher than meeting the 90% removal requirement, additional annualized costs are

*Incremental cost effectiveness (which is a term used by EPA) reflects the change in annualized costs divided by the change in SO_2 emission reductions for two regulatory options (i.e., marginal cost).[2] It is not equivalent to the difference in cost-effectiveness between two regulatory options.

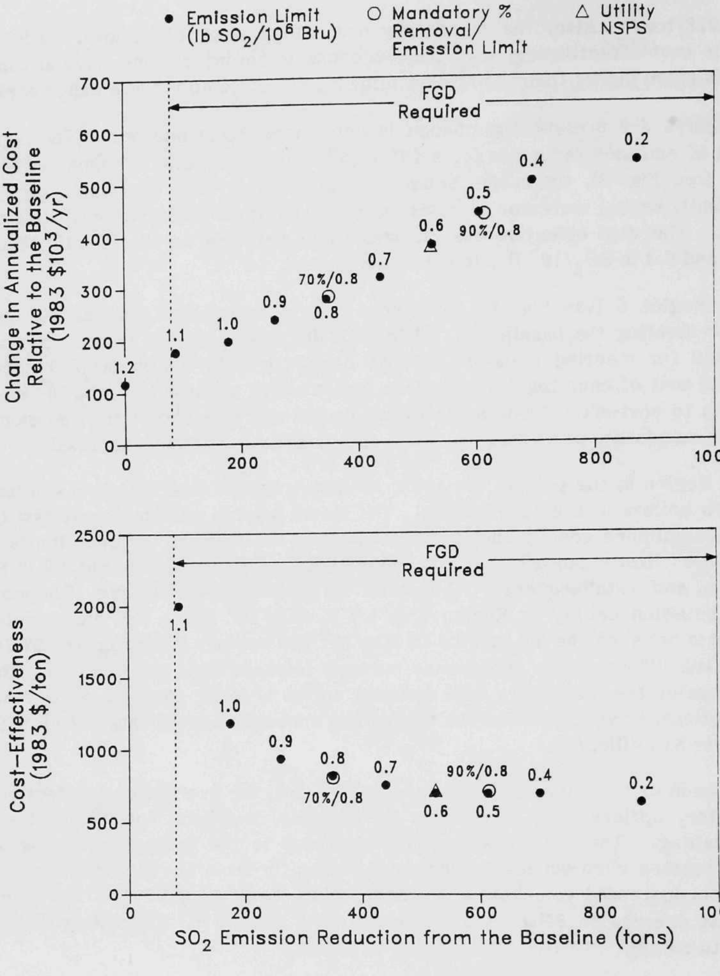


FIGURE 6 SO_2 Emission Reductions Corresponding with Various Emission Ceilings: Cost-Effectiveness and Changes in Annualized Cost for 400 x 10^6 Btu/h Boilers, Region 3

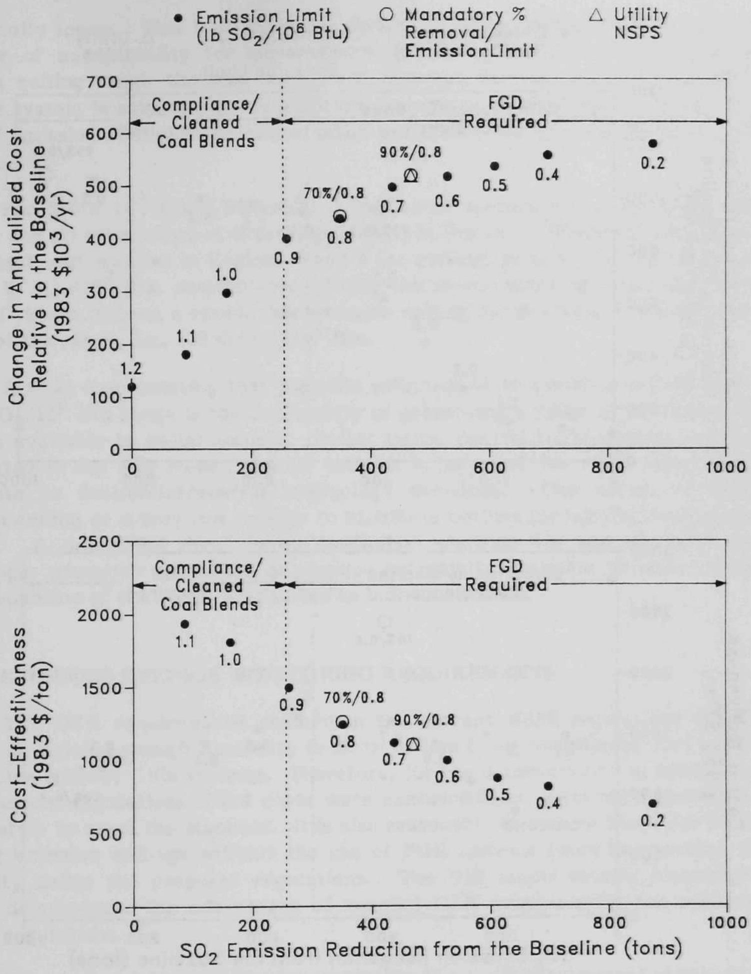


FIGURE 7 SO_2 Emission Reductions Corresponding with Various Emission Ceilings: Cost-Effectiveness and Changes in Annualized Cost for 400 x 10^6 Btu/h Boilers, Region 5

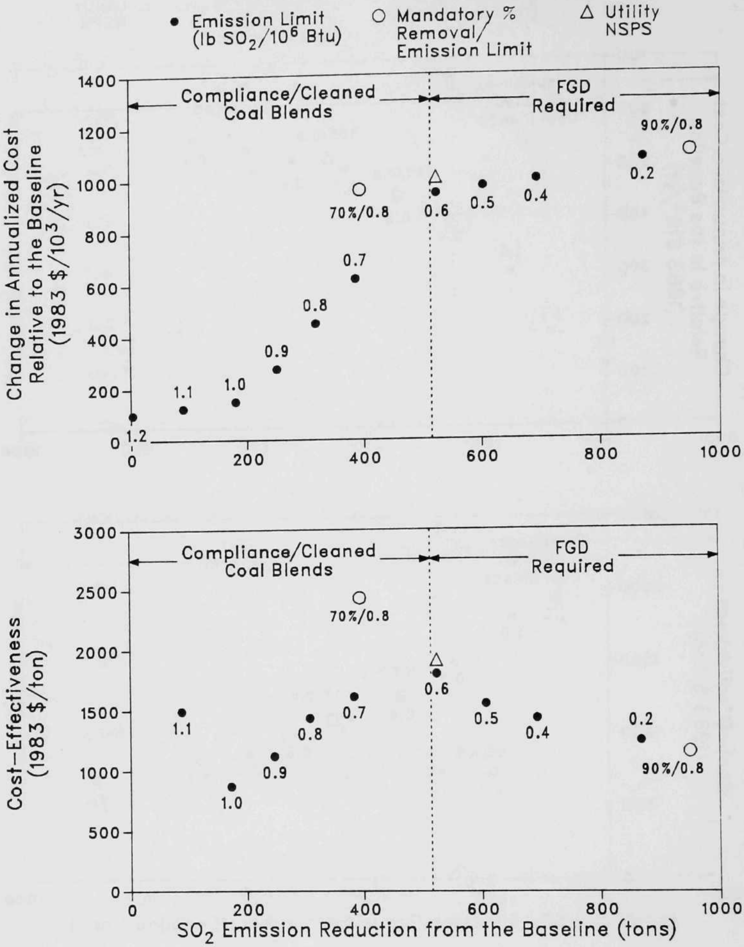


FIGURE 8 SO_2 Emission Reductions Corresponding with Various Emission Ceilings: Cost-Effectiveness and Changes in Annualized Cost for 400 x 10^6 Btu/h Boilers, Region 8

substantially lower. This illustrates the danger in using cost-effectiveness as the only indicator of acceptability for a regulatory option. Finally, for this boiler size and emission ceiling range the cost increment between burning cleaned coal and using a scrubber system is substantial. In addition, the use of cleaned coal to meet this middle range of emission ceilings reduces secondary environmental impacts associated with FGD systems.

For 400 x 10^6 Btu/h boilers, the least-cost method for meeting the regulatory baseline and all other more stringent options is, in Region 3, FGD systems. Cleaned coal is the least-cost method in Regions 5 and 8 for ceilings greater than 0.9 lb $SO_2/10^6$ Btu and 0.7 lb $SO_2/10^6$ Btu, respectively. Using the same reasoning as discussed above for 100 x 10^6 Btu/h boilers, a reasonable emission ceiling for the boilers is somewhere in the middle of the range, i.e., 0.8 lb $SO_2/10^6$ Btu.

A final consideration that supports selection of an emission ceiling in the 0.7 to 0.9 lb $SO_2/10^6$ Btu range is the desirability of preserving a range of possible compliance methods available to boiler owners. Boiler types, control technologies, and coal types are limited in the NIB model, and no account is taken of the many other factors that contribute to fuel/boiler/control technology decisions. One effect of setting the emission ceiling at a very low level is to eliminate options for burning coal in an optimal manner. A mid-range level, while implicitly requiring the use of sulfur reduction technology, preserves a number of choices potentially available to boiler owners, and allows selection of the one(s) best suited to individual needs.

4.2 CONTINUOUS EMISSION MONITORING REQUIREMENTS

The CEM requirements defined in the current NSPS regulations (40 CFR §60 Subpart D) provide enough flexibility to allow boilers firing compliance coal to operate in compliance without CEM systems. Therefore, for the determination of operational costs under current regulations, CEM costs were excluded from units not required to use an FGD system to meet the standard. It is also reasonable to assume that coal-fired boilers meeting emission ceilings without the use of FGD systems could be provided the same flexibility under the proposed regulations. The NIB model results presented in this section demonstrate the advantages of keeping CEM requirements the same as under current regulations.

Figures 9 and 10 show how incorporation of a CEM requirement changes the cost-effectiveness estimates for 100, 250, and 400 x 10^6 Btu/h boilers in Regions 5 and 8 that would be meeting the emission ceiling regulatory options without using FGD systems. As discussed in Sec. 2, the CEM costs used in estimating the cost of boiler operation under the regulatory options are \$143,000 and \$110,000, respectively, for boilers using or not using FGD systems. For the cost-effectiveness estimates in Figs. 9 and 10, a \$110,000 amount was subtracted from the annualized cost of meeting a regulatory option in cases where a scrubber system is not used. Boilers using FGD systems to comply with a regulatory option were not included in this comparison.

In Region 5 (see Fig. 9), the difference in cost-effectiveness estimates for boilers with and without CEM devices exceeds \$1,000/ton for the following cases: 250 x 10^6 Btu/h boilers meeting a ceiling of 1.0 lb $SO_2/10^6$ Btu and 100 x 10^6 Btu/h boilers meeting

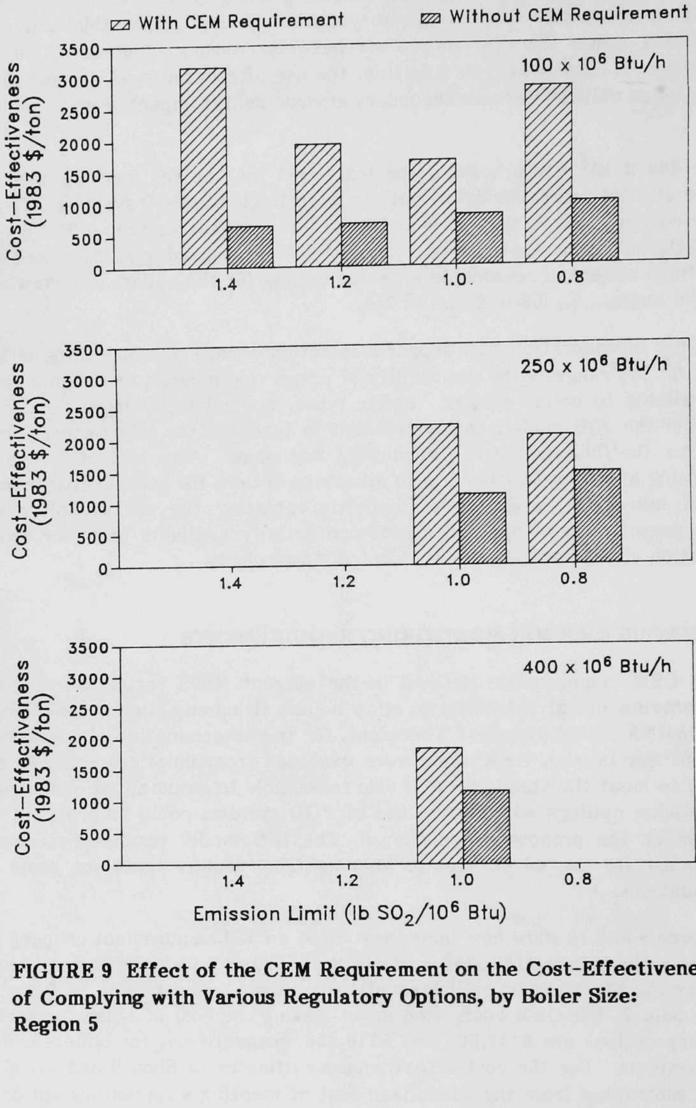


FIGURE 9 Effect of the CEM Requirement on the Cost-Effectiveness of Complying with Various Regulatory Options, by Boiler Size: Region 5

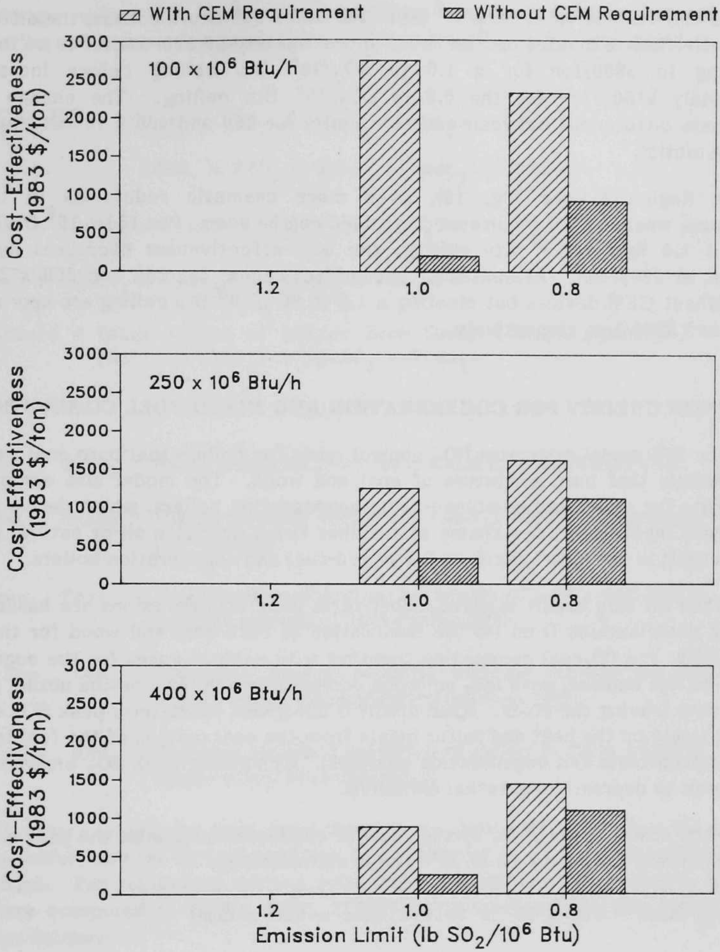


FIGURE 10 Effect of the CEM Requirement on the Cost-Effectiveness of Complying with Various Regulatory Options, by Boiler Size: Region 8

ceilings of 1.4, 1.2 and 0.8 lb $SO_2/10^6$ Btu. For 100 x 10^6 Btu/h boilers, the difference in cost-effectiveness estimates decline from approximately $2,500/ton for a 1.4 lb $SO_2/10^6$ Btu ceiling to $850/ton for a 1.0 lb $SO_2/10^6$ Btu ceiling before increasing to approximately $1800/ton for the 0.8 lb $SO_2/10^6$ Btu ceiling. The change in cost-effectiveness differences between emission limits for 250 and 400 x 10^6 Btu/h boilers is not as substantial.

In Region 8 (see Fig. 10), even more dramatic reductions in the cost-effectiveness when a CEM requirement is added can be seen. For 100 x 10^6 Btu/h boilers meeting a 1.0 lb $SO_2/10^6$ Btu ceiling, the cost-effectiveness decreases by roughly $2,500/ton to $205/ton. Estimates of cost-effectiveness for 250 and 400 x 10^6 Btu/h boilers without CEM devices but meeting a 1.0 lb $SO_2/10^6$ Btu ceiling are approximately $340/ton and $250/ton, respectively.

4.3 EMISSION CREDITS FOR COGENERATION AND MIXED-FUEL COMBUSTION

The NIB model estimates SO_2 control costs for boilers that burn coal exclusively and for boilers that burn a mixture of coal and wood. The model also computes SO_2 control costs for coal-fired combined-cycle cogeneration boilers, which derive a portion of their heat input from the exhaust of turbines firing distillate oil or natural gas. The emission credit is computed similarly for mixed-fuel and cogeneration boilers.

When an SO_2 credit is given, short-term peak SO_2 emissions are based on heat and sulfur contributions from (1) the combustion of both coal and wood for the mixed-fuels analysis, and (2) coal combustion together with exhaust gases for the cogeneration analysis. In this manner, peak SO_2 emission computations determine the actual peak SO_2 emission rate leaving the stack. When credit is not given, short-term peak SO_2 emissions are based solely on the heat and sulfur inputs from the coal portion of the fuel inputs (for both the mixed-fuels and cogeneration analyses). Computing peak SO_2 emissions in this fashion tends to overestimate actual emissions.

When credit is given for mixed fuels or cogeneration plants, the peak short-term SO_2 emission rate (SO_2 peak, in lb/10^6 Btu) is estimated by:

$$SO_2\ \text{Peak} = 2.0 \times 10^4 \times \overline{\text{Sulf}} \,/\left(\overline{\text{Heat}} \times \overline{\text{RSD}} \times \overline{\text{Cem}}\right) \tag{1}$$

where:

$\overline{\text{Sulf}}$ = average sulfur content (%),

$\overline{\text{Heat}}$ = average higher heating value (Btu/lb),

$\overline{\text{RSD}}$ = relative standard deviation of the sulfur content of the fuel (dimensionless), and

$\overline{\text{Cem}}$ = average fractional amount of sulfur in the flue gas.

Average values for these four variables are computed by combining the characteristics and combustion properties of the various fuels that provide heat input to the boiler:

$$\overline{Cem} \times \overline{RSD} = [(Cem_1 \times RSD_1 \times Sulf_1 \times Frac_1) + (Cem_2 \times RSD_2 \times Sulf_2 \times Frac_2)]/TotSulf \quad (2)$$

$$\overline{Sulf} = (Sulf_1 \times Frac_1) + (Sulf_2 \times Frac_2) \quad (3)$$

$$\overline{Heat} = (Heat_1 \times Frac_1) + (Heat_2 \times Frac_2) \quad (4)$$

$$TotSulf = \text{Total amount of sulfur from fuels 1 and 2 (percent)} \; (Sulf_1 \times Frac_1) + (Sulf_2 \times Frac_2) \quad (5)$$

where:

$Sulf_1$, $Sulf_2$ = Sulfur contents from fuels 1 and 2, respectively (%),

$Heat_1$, $Heat_2$ = Higher heating values for fuels 1 and 2, respectively (10^6 Btu/lb),

$Frac_1$, $Frac_2$ = Fractional contribution by weight of fuel 1 and fuel 2 to total amount of fuel combusted,

Cem_1, Cem_2 = Fractional amount of sulfur entering the flue gas for fuels 1 and 2, respectively (fraction), and

RSD_1, RSD_2 = Relative standard deviation of sulfur in fuels 1 and 2, respectively (dimensionless).

Allowing a credit for heat input from clean (low-sulfur) fuel has the effect of raising the sulfur content in fuel that can be combusted in compliance with the short-term standard. For regulatory options requiring a percentage SO_2 removal, peak SO_2 emissions are computed as shown in Eq. 1, and the percentage removal requirement is computed as follows:

$$\text{Percent Removal} = \{1.0 - [1.0 - (RegPer/100)]\} \times (\overline{PotEms}/Act\ SO_2) \quad (6)$$

where:

RegPer = Percentage removal required by regulation (%),

$\overline{PotEms}$ = Potential SO_2 emissions from the fuel mixture (lb/10^6 Btu), and

$ActSO_2$ = Actual SO_2 emissions for the fuel mixture (lb/10^6 Btu).

The analysis of emission credits is based on a comparison of systems receiving and not receiving credit for cogeneration and nonfossil fuel combustion. Therefore, the incremental cost ($/ton) is the additional cost of each ton of SO_2 removed as a result of not allowing credit. The incremental cost value should not be compared to cost-effectiveness values presented elsewhere in the report. It should also be stressed that the annual emission levels of the credited boilers are the same as those of boilers not being used for mixed-fuel combustion or cogeneration. The noncredit situation actually represents an additional emission reduction requirement.

Table 8 summarizes the NIB model results regarding the emissions and annualized costs for a combined-cycle cogeneration system in which the coal-fired boiler receives 25% of its heat input from turbine exhaust. The turbine is fired by low-sulfur distillate oil. The cost of the distillate oil is treated as fuel cost to the boiler. As is apparent from the incremental cost estimates for systems meeting emission ceilings, the costs are highest when the source switches to a lower-sulfur coal. For situations where an FGD system is being used to meet the regulatory option (low emission ceiling or mandatory percentage removal), a small change in scrubber efficiency results in only a small incremental cost. Thus, with a mandatory control regulation, allowance for credit is not tremendously important.

Credits for combusting nonfossil fuel were analyzed for Regions 1, 4, and 10, since most nonfossil fuel is consumed by the paper industry located in these regions. These results are summarized in Table 9. For this analysis, wood (or wood waste) is assumed to be available as a by-product at an industrial facility, with costs reflecting handling and processing. Not allowing credit for combusting nonfossil fuel to meet an emission ceiling of 0.8 lb $SO_2/10^6$ Btu results in an additional SO_2 removal cost of $1,100-$2,100/ton. At a 0.6 lb $SO_2/10^6$ Btu ceiling, this incremental cost increases to as much as $4,500/ton for 100 x 10^6 Btu/h boilers forced to switch from cleaned coal to an FGD system when not receiving credit. If an FGD system is being used to meet the emission standard in both the credit and noncredit cases, incremental costs are reduced to $300-500/ton.

Based on this analysis, it appears that not allowing credit for nonfossil fuel combustion or cogeneration for boilers required to use FGD systems (i.e., mandatory percentage removal or a very low emission ceiling) results in an incremental cost of $300-$500/ton. For boilers not using FGD systems for the credit case, but switching to an FGD system or cleaner coal for the noncredit case, the incremental costs are in the $1,500-3,000/ton range.

These results are for a cogeneration system and a mixed-fuel boiler receiving 25% of its heat input from low-sulfur fuel. Boilers receiving greater proportions of low-sulfur fuel would have lower incremental costs.

TABLE 8 Effect of Emission Credits on Regulatory Options for Combined-Cycle Cogeneration Boilers: Least-Cost Compliance Method, Emissions, and Incremental Costs[a]

Region, Boiler Size (10^6 Btu/h)	No Credit: Control Method, (% Removal)[b]	No Credit: Annualized Cost (1983 $\$10^3$/yr)	No Credit: Emissions (tons/yr)	Credit: Control Method, (% Removal)[b]	Credit: Annualized Cost (1983 $\$10^3$/yr)	Credit: Emissions ($/ton)	Incremental Cost[c] ($/ton)
			1.0 lb $SO_2/10^6$ Btu Ceiling				
Region 3							
100	PCC	4,705	200	PCC	4,665	234	1,183
250	PCC	11,116	499	PCC	11,010	584	1,248
400	dry, 78	16,374	676	-	16,216	889	738
Region 5							
100	PCC	4,813	188	-	4,780	222	971
250	PCC	11,373	471	-	11,288	556	1,004
400	PCC	16,785	753	-	16,645	889	1,033
Region 8							
100	-	4,136	184	-	4,127	222	219
250	-	9,530	460	-	9,507	555	239
400	-	13,735	737	-	13,698	888	243
			0.8 lb $SO_2/10^6$ Btu Ceiling				
Region 3							
100	PCC	4,754	164	PCC	4,714	193	1,365
250	PCC	11,236	410	PCC	11,139	482	1,345
400	dry, 83	16,433	541	dry, 77	16,363	704	432
Region 5							
100	PCC	4,856	161	PCC	4,822	182	1,620
250	PCC	11,490	404	PCC	11,398	456	1,756
400	PCC	16,996	646	PCC	16,829	729	1,878
Region 8							
100	PCC	4,184	157	PCC	4,138	178	2,146
250	PCC	9,668	392	PCC	9,536	446	2,449
400	PCC	13,962	627	PCC	13,745	714	2,506

TABLE 8 (Cont'd)

Region, Boiler Size (10^6 Btu/h)	No Credit			Credit			
	Control Method, (% Removal)[b]	Annualized Cost (1983 $\$10^3$/yr)	Emissions (tons/yr)	Control Method, (% Removal)[b]	Annualized Cost (1983 $\$10^3$/yr)	Emissions ($/ton)	Incremental Cost[c] ($/ton)
	0.6 lb $SO_2/10^6$ Btu Ceiling						
Region 3							
100	sodm, 87	4,901	101	PCC	4,795	145	2,420
250	sodm, 87	11,343	253	sodm, 83	11,320	330	303
400	dry, 87	16,507	405	dry, 83	16,439	528	555
Region 5							
100	sodm, 61	5,039	107	PCC	4,895	145	3,767
250	sodm, 61	11,718	267	PCC	11,592	363	1,322
400	dry, 87	17,090	405	dry, 87	17,013	527	633
Region 8							
100	sodm, 38	4,414	111	PCC	4,211	144	6,074
250	sodm, 38	10,018	277	PCC	9,745	361	3,274
400	sodm, 38	14,391	444	PCC	14,087	577	2,283
	1979 Utility NSPS[d]						
Region 3							
100	sodm, 87	4,901	101	sodm, 83	4,891	132	318
250	sodm, 87	11,343	253	sodm, 83	11,320	330	303
400	dry, 87	16,507	405	dry, 83	16,439	528	555
Region 5							
100	sodm, 68	5,046	88	sodm, 60	5,038	109	363
250	sodm, 87	11,721	253	dry, 86	11,697	364	215
400	dry, 89	17,069	445	dry, 86	16,979	582	648
Region 8							
100	sodm, 65	4,435	62	sodm, 58	4,429	75	424
250	sodm, 65	10,065	155	sodm, 58	10,053	187	378
400	dry, 71	14,423	417	dry, 63	14,385	530	343

TABLE 8 (Cont'd)

Region, Boiler Size (10^6 Btu/h)	No Credit: Control Method, (% Removal)[b]	No Credit: Annualized Cost (1983 $\$10^3$/yr)	No Credit: Emissions (tons/yr)	Credit: Control Method, (% Removal)[b]	Credit: Annualized Cost (1983 $\$10^3$/yr)	Credit: Emissions ($/ton)	Incremental Cost[c] ($/ton)
	70% Removal with a 0.8 lb $SO_2/10^6$ Btu Ceiling						
Region 3							
100	sodm, 83	4,890	135	sodm, 77	4,877	176	319
250	sodm, 83	11,317	338	sodm, 77	11,286	440	304
400	dry, 83	16,433	540	dry, 77	16,363	703	432
Region 5							
100	sodm, 68	5,046	88	sodm, 77	5,035	176	127
250	sodm, 83	11,695	338	dry, 83	11,656	439	388
400	dry, 87	17,007	537	dry, 83	16,915	703	547
Region 8							
100	sodm, 65	4,435	62	sodm, 58	4,429	75	424
250	sodm, 65	10,065	155	sodm, 55	10,039	410	100
400	dry, 64	14,389	516	dry, 55	14,348	656	297

[a]Assumptions or conditions: (1) 25% of the heat input from distillate-oil-fired turbine exhaust supplied to coal-fired boilers, (2) an annual capacity factor of 0.6 used, (3) ANL regulatory baseline used as the benchmarck, (4) CEM requirements included, (5) EPA coal costs used.

[b]Control method abbreviations: PCC = partially cleaned coal, dry = lime-spray drying, and sodm = sodium throwaway. The percentage removed is given where applicable.

[c]Incremental cost = the change in annualized cost divided by the change in emission reduction between the credit and no credit cases.

[d]Another, similar option tested, 90% mandatory removal with a 0.8 lb $SO_2/10^6$ Btu ceiling, gives very similar results; hence, that regulatory option is not included in the table.

TABLE 9 Effect of Emission Credits on Regulatory Options for Nonfossil Fuel Combustion in Coal-Fired Boilers: Least-Cost Compliance Method, Emissions and Incremental Cost[a]

Region, Boiler Size (10^6 Btu/h)	No Credit: Control Method, (% Removal)[b]	No Credit: Annualized Cost, (1983 $$10^3$/yr)	No Credit: Emissions (tons/yr)	Credit: Control Method, (% Removal)[b]	Credit: Annualized Cost, (1983 $$10^3$/yr)	Credit: Emissions ($/ton)	Credit: Incremental Cost[c] ($/ton)
1.0 lb $SO_2/10^6$ Btu Ceiling							
Region 1							
100	PCC	4,478	173	-	4,446	220	707
250	PCC	10,263	434	-	10,173	550	776
400	PCC	14,879	694	-	14,733	880	783
Region 4							
100	PCC	4,245	185	PCC	4,192	229	1,209
250	PCC	9,692	433	-	9,548	550	1,236
400	PCC	13,965	693	-	13,732	880	1,242
Region 10							
100	PCC	4,121	171	PCC	4,038	234	1,321
250	PCC	9,180	428	PCC	8,989	585	1,214
400	PCC	13,118	685	PCC	12,814	937	1,207
0.8 lb $SO_2/10^6$ Btu Ceiling							
Region 1							
100	PCC	4,523	147	PCC	4,471	178	1,720
250	PCC	10,399	368	PCC	10,240	444	2,067
400	PCC	15,099	588	PCC	14,842	711	2,100
Region 4							
100	PCC	4,294	149	PCC	4,236	192	1,382
250	PCC	9,829	367	PCC	9,669	444	2,085
400	PCC	14,187	587	PCC	13,927	710	2,118
Region 10							
100	PCC	4,178	143	PCC	4,111	179	1,888
250	PCC	9,339	358	PCC	9,157	447	2,037
400	dry, 62	13,286	534	PCC	13,081	716	1,128

TABLE 9 (Cont'd)

Region, Boiler Size (10^6 Btu/h)	No Credit: Control Method, (% Removal)[b]	No Credit: Annualized Cost (1983 $\$10^3$/yr)	No Credit: Emissions (tons/yr)	Credit: Control Method, (% Removal)[b]	Credit: Annualized Cost (1983 $\$10^3$/yr)	Credit: Emissions ($/ton)	Credit: Incremental Cost[c] ($/ton)
			0.6 lb $SO_2/10^6$ Btu Ceiling				
Region 1							
100	sodm, 87	4,727	99	PCC	4,530	143	4,529
250	sodm, 87	10,634	248	PCC	10,419	357	1,977
400	dry, 87	15,249	397	PCC	15,133	571	678
Region 4							
100	sodm, 61	4,494	101	PCC	4,302	144	4,481
250	sodm, 61	10,075	252	PCC	9,850	356	2,168
400	sodm, 61	14,445	404	PCC	14,220	570	1,353
Region 10							
100	sodm, 71	4,304	100	PCC	4,180	139	3,001
250	sodm, 71	9,407	250	PCC	9,363	348	456
400	sodm, 71	13,331	401	dry, 62	13,288	527	337
			1979 Utility NSPS				
Region 1							
100	sodm, 87	4,727	99	sodm, 83	4,717	132	318
250	sodm, 87	10,634	248	sodm, 83	10,610	329	304
400	dry, 87	15,249	397	dry, 83	15,177	526	552
Region 4							
100	sodm, 68	4,500	83	sodm, 58	4,491	109	367
250	sodm, 68	10,089	208	sodm, 58	10,068	272	333
400	sodm, 68	14,468	333	sodm, 58	14,435	435	320
Region 10							
100	sodm, 71	4,304	100	sodm, 62	4292	132	387
250	sodm, 71	9,407	250	sodm, 62	9379	329	358
400	dry, 71	13,331	401	dry, 62	13288	527	337

TABLE 9 (Cont'd)

Region, Boiler Size (10^6 Btu/h)	No Credit: Control Method, (% Removal)[b]	No Credit: Annualized Cost (1983 $\$10^3$/yr)	No Credit: Emissions (tons/yr)	Credit: Control Method, (% Removal)[b]	Credit: Annualized Cost (1983 $\$10^3$/yr)	Credit: Emissions ($/ton)	Incremental Cost[c] ($/ton)
			70% Removal with a 0.8 lb $SO_2/10^6$ Btu Ceiling				
Region 1							
100	sodm, 83	4,716	132	sodm, 77	4,702	175	320
250	sodm, 83	10,609	331	sodm, 77	10,576	439	305
400	sodm, 83	15,176	530	dry, 77	15,102	702	430
Region 4							
100	sodm, 68	4,500	83	sodm, 58	4,491	109	367
250	sodm, 68	10,089	208	sodm, 58	10,068	272	333
400	sodm, 68	14,468	333	sodm, 58	14,435	435	321
Region 10							
100	sodm, 64	4,294	125	sodm, 53	4,279	164	392
250	sodm, 64	9,386	312	sodm, 53	9,350	410	361
400	dry, 64	13,297	499	sodm, 53	13,251	656	292

[a]Assumptions or conditions: (1) 25% of the heat input from distillate-oil-fired turbine exhaust supplied to coal-fired boilers, (2) an annual capacity factor of 0.6 used, (3) ANL regulatory baseline used as the benchmarck, (4) CEM requirements included, (5) EPA coal costs used, (6) wood has essentially no cost.

[b]Control method abbreviations: PCC = partially cleaned coal, dry = lime-spray drying, and sodm = sodium throwaway. The percentage removal is given where applicable.

[c]Incremental cost = the change in annualized cost divided by the change in emission reduction between the credit and no credit cases.

5 OTHER FACTORS AFFECTING REGULATORY OPTIONS

5.1 ALTERNATIVE COAL PRICES

Because of the large effect of fuel price on total annualized boiler cost, two sets of coal quality and cost data were used in the NIB model to compare the cost-effectiveness of the regulatory options relative to the regulatory baseline. The differences between these data sets are presented in Figs. 11-13 for Regions 3, 5, and 8, respectively. Data for the first set, which was used by EPA, is shown in Table 10. The second set, from the AUSM Coal Supply Model data base,[5] is presented in Table 11 for Regions 3, 5, and 8. These data were adjusted by 10% to approximate the cost difference between utility and industrial purchases. In both data sets, the cost data were also adjusted to reflect 1983 dollar values.

Model results using these alternative coal data are summarized in Table 12. In Region 3, the availability of a low-sulfur coal, even at a significant premium, results in *not* selecting an FGD system to meet either the 1.0 lb $SO_2/10^6$ Btu ceiling for 400 x 10^6 Btu/h boilers or the 0.8 lb $SO_2/10^6$ Btu ceiling for 250 x 10^6 Btu/h boilers. In Region 5,

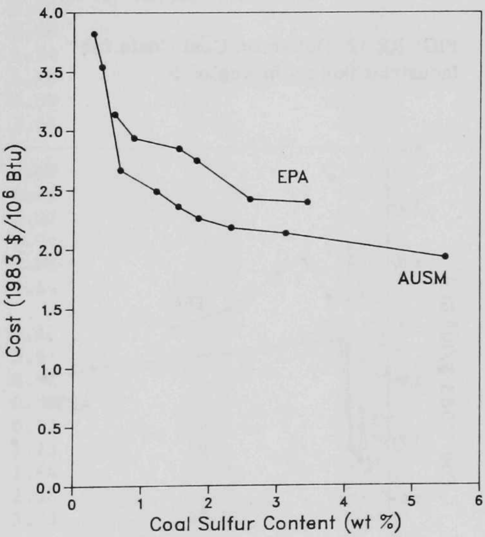


FIGURE 11 Delivered Coal Costs for Industrial Boilers in Region 3

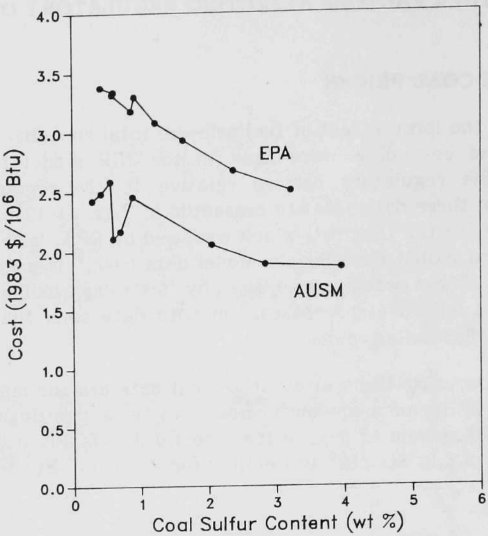


FIGURE 12 Delivered Coal Costs for Industrial Boilers in Region 5

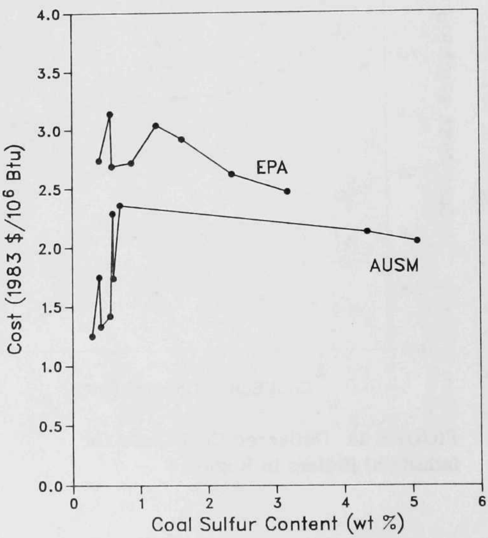


FIGURE 13 Delivered Coal Costs for Industrial Boilers in Region 8

TABLE 10 Characteristics and Costs of Delivered Coal for Industrial Boilers: EPA Data Set

Region	Sulfur Content (%)	Ash Content (%)	Heating Value (Btu/lb)	Cost (1983 $\$/10^6$ Btu)
1	0.61	11.9	12,750	3.76
	0.88	11.9	12,750	3.71
	1.33	13.0	12,800	3.65
	1.87	13.0	13,150	3.46
	2.67	13.0	12,850	3.16
	3.43	13.0	12,375	3.26
2	0.59	11.9	12,500	3.52
	0.87	11.9	12,600	3.45
	1.33	11.4	12,750	3.30
	1.86	13.0	13,050	3.13
	2.67	13.0	12,850	2.82
	3.49	13.0	12,600	2.85
3	0.60	11.8	12,645	3.14
	0.88	12.4	12,700	2.94
	1.54	14.6	12,710	2.85
	1.80	12.2	12,670	2.75
	2.59	13.0	12,500	2.42
	3.44	13.0	12,430	2.39
4	0.60	11.7	12,720	3.19
	0.88	12.3	12,735	2.98
	1.32	12.3	12,720	2.96
	1.77	11.9	12,430	2.88
	2.45	11.9	11,820	2.80
	3.14	11.8	11,350	2.62
5	0.42	6.9	8,825	3.38
	0.61	6.9	8,825	3.34
	0.92	6.9	8,825	3.30
	0.59	11.0	12,525	3.32
	0.87	11.0	12,555	3.18
	1.23	10.5	11,795	3.08
	1.64	10.9	11,485	2.93
	2.38	12.2	11,465	2.67
	3.23	12.0	11,660	2.50

TABLE 10 (Cont'd)

Region	Sulfur Content (%)	Ash Content (%)	Heating Value (Btu/lb)	Cost (1983 $/$10^6$ Btu)
6	0.41	7.3	8,570	3.49
	0.59	7.3	8,570	3.39
	0.89	7.3	8,570	3.32
	0.59	12.1	12,415	3.34
	0.71	11.8	10,335	3.21
	1.07	15.0	10,275	3.20
	1.73	11.8	12,135	3.19
	2.52	12.2	12,130	3.09
	3.31	12.3	11,945	2.96
7	0.40	6.0	8,500	2.74
	0.59	6.0	8,500	2.69
	0.88	6.0	8,500	2.72
	0.57	10.0	11,930	3.14
	0.84	12.4	12,165	3.08
	1.25	12.4	12,030	3.04
	1.63	11.1	11,445	2.92
	2.37	11.1	11,410	2.62
	3.19	11.1	11,500	2.47
8	0.42	8.4	8,770	1.40
	0.59	6.9	8,620	1.39
	0.90	6.9	8,620	1.28
	0.51	10.0	10,850	1.99
	0.71	10.0	10,330	1.86
	1.07	10.0	10,285	1.87
9	0.44	7.3	9,250	2.84
	0.64	7.3	9,250	2.74
	0.96	7.3	9,250	2.65
	0.50	11.3	10,505	2.80
	0.70	11.3	10,100	2.82
	1.02	16.3	9,825	2.77
10	0.45	10.0	9,500	2.66
	0.66	10.0	9,500	2.60
	0.99	10.0	9,500	2.09
	0.52	10.0	10,940	3.18
	0.75	10.0	10,940	2.97
	1.14	10.0	10,940	2.84

Source: Ref. 3.

TABLE 11 Characteristics and Costs of Delivered Coal for Industrial Boilers: AUSM Data Set for Regions 3, 5, and 8[a]

Region	Sulfur Content (%)	Ash Content (%)	Heating Value (Btu/lb)	Cost (1983 $\$/10^6$ Btu)
3[b]	5.49	15.8	11,560	1.92
	3.12	13.9	12,490	2.13
	2.31	10.3	13,170	2.18
	1.83	11.4	13,290	2.26
	1.53	9.3	13,600	2.36
	1.21	7.8	13,860	2.49
	0.68	8.2	13,500	2.67
	0.41	9.2	11,620	3.54
	0.29	7.1	8,321	3.82
5[c]	3.97	12.0	11,330	1.85
	2.85	11.2	11,380	1.88
	2.06	8.6	11,760	2.05
	0.71	11.9	6,346	2.17
	0.60	10.4	6,871	2.11
	0.89	7.5	13,160	2.46
	0.56	7.6	8,354	2.59
	0.42	9.2	8,475	2.49
	0.29	7.1	8,321	2.43
8[d]	5.09	15.4	11,570	2.05
	4.36	10.6	12,460	2.13
	0.71	11.9	6,346	2.36
	0.60	10.4	6,871	2.29
	0.56	7.6	8,354	1.42
	0.61	11.0	12,160	1.74
	0.42	9.2	8,475	1.33
	0.40	9.2	11,620	1.75
	0.29	7.1	8,321	1.25

[a]All data extracted from Ref. 5; coal costs shown adjusted by 10% to reflect the difference between utility and industrial coal prices.

[b]Derived from data for Maryland.

[c]Derived from data for Illinois.

[d]Derived from data for Wyoming.

TABLE 12 Cost Effectiveness of Meeting Regulatory Options in Regions 3, 5 and 8, Based on AUSM Coal Price Data (\$/ton of SO_2 removed)

Region, Boiler Size (10^6 Btu/h)	Emission Ceiling (lb $SO_2/10^6$ Btu)						1979 Utility NSPS	Mandatory % Removal	
	1.4	1.2	1.0	0.8	0.6	0.4		90[b]	70[b]
Region 3									
100	3,100	1,844	1,698	1,695	1,933[c,d]	1,665[c,d]	1,933	1,606	2,333
250	e	e	2,589	2,171[d]	1,606[c,d]	1,281[c,d]	1,606	1,203	2,256
400	e	e	2,207[c]	1,408[c,d]	1,058[c,d]	906[c,d]	1,058	989	1,409
Region 5									
100	2,652	1,965	1,747	1,920	2,090[c,d]	1,802[c,d]	1,845	1,548	1,845
250	e	e	2,717	1,989	1,815[c,d]	1,460[c,d]	1,509	1,194	1,509
400	e	e	2,310	1,604[c]	1,451[c,d]	1,180[c,d]	1,217	977	1,217
Region 8									
100	e	e	f	f	8,736[d]	6,177[c,d]	4,321	3,282	4,321
250	e	e	f	f	5,744[d]	3,977[c,d]	2,816	2,167	2,816
400	e	e	f	f	4,924[d]	3,273[c,d]	2,335	1,810	2,335

[a]Assumptions or conditions: (1) ANL regulatory baseline used as benchmark and (2) CEM requirements included.

[b]In combination with a 0.8 lb $SO_2/10^6$ Btu emission ceiling.

[c]At this point, an FGD system is selected as the least-cost compliance method, based on AUSM coal data.

[d]At this point, an FGD system is selected as the least-cost compliance method, based on EPA coal data.

[e]The emission ceiling is at or above the regulatory baseline, resulting in zero or negative cost-effectiveness values.

[f]The model chooses the same coal for meeting the 1.2 lb $SO_2/10^6$ Btu limit.

use of the alternative coal data results in a shift away from FGD systems for 400 x 10^6 Btu/h boilers meeting a 0.8 lb $SO_2/10^6$ Btu emission ceiling. In Region 8, compliance with a 0.6 lb $SO_2/10^6$ Btu emission ceiling is attained by burning low-sulfur (cleaned) coal with an FGD system.

Figures 14-16 show how the cost-effectiveness of meeting each regulatory option changes, depending on which coal cost data are used. For 100 x 10^6 Btu/h boilers in Region 3 (see Fig. 14), use of the alternative coal data produces lower or nearly equal cost-effectiveness estimates for all regulatory options. For larger boilers, however, the opposite occurs, except in one case (250 x 10^6 Btu/h boilers meeting a 1.0 lb $SO_2/10^6$ Btu ceiling).

In Region 5 (see Fig. 15), the cost-effectiveness of meeting the emission ceiling regulatory options is generally higher for all boiler sizes when the AUSM data are used,

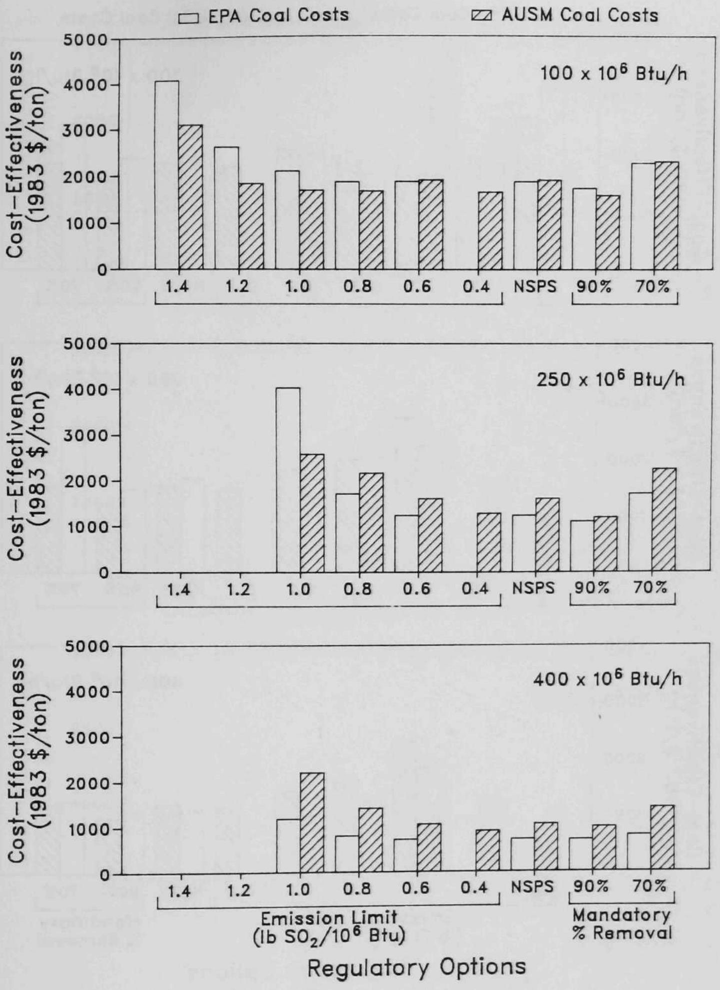


FIGURE 14 Effect of Different Delivered Coal Costs on the Cost-Effectiveness of Complying with Various Regulatory Options, by Boiler Size: Region 3

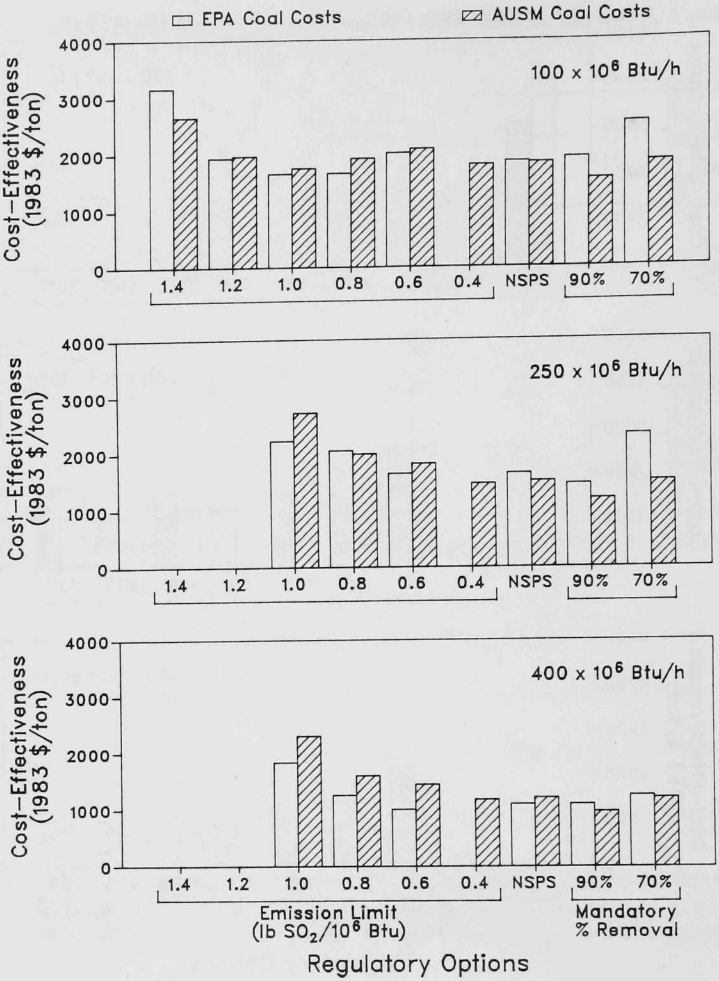


FIGURE 15 Effect of Different Delivered Coal Costs on the Cost-Effectiveness of Complying with Various Regulatory Options, by Boiler Size: Region 5

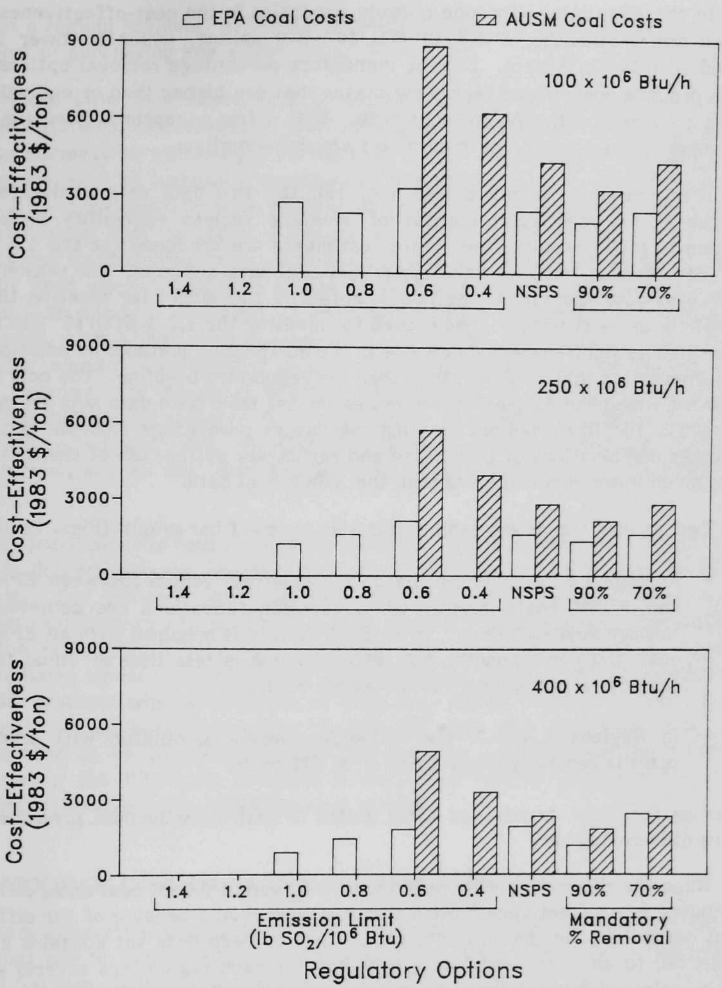


FIGURE 16 Effect of Different Delivered Coal Costs on the Cost-Effectiveness of Complying with Various Regulatory Options, by Boiler Size: Region 8

relative to the EPA data. The one notable exception is the cost-effectiveness of 100 x 10^6 Btu/h boilers meeting a 1.4 lb $SO_2/10^6$ Btu ceiling, which is lower than when calculated with the EPA data. For the mandatory percentage removal options, the EPA coal data produce cost-effectiveness estimates that are higher than or equivalent to the estimates produced by the AUSM coal data. With a few exceptions, however, the cost-effectiveness values based on both data sets are quite similar.

In contrast, in Region 8 (see Fig. 16), the two data sets produce substantial differences in the cost-effectiveness of meeting various regulatory options. One observation is that no cost-effectiveness estimates are produced for the 1.0 and 0.8 lb $SO_2/10^6$ Btu emission ceilings when the AUSM coal data are used. The reason for this is that the least-cost compliance method selected by the model for meeting these limits consists of the same type of coal as is used for meeting the 1.2 lb $SO_2/10^6$ Btu regulatory baseline. Hence, since there is no change in the compliance method, no additional cost is incurred in meeting that ceiling rather than the regulatory baseline. The only regulatory scenarios for which the cost-effectiveness estimates from both data sets are comparable are for 400 x 10^6 Btu/h boilers meeting mandatory percentage removal requirements. For all other combinations of boiler size and regulatory option, use of the EPA coal data produces much lower removal costs than the AUSM coal data.

Two general trends are exhibited in this series of bar graphs (Figs. 14-16):

- In Region 3, a lower estimate of cost-effectiveness (between EPA and AUSM coals) results when emission reductions are achieved through fuel switching. If an FGD system is required with an EPA coal, the corresponding cost-effectiveness is less than or equal to the cost-effectiveness for the AUSM coal.

- In Regions 5 and 8, the cost-effectiveness associated with EPA coals is generally lower than for AUSM coals.

The reasons for these trends and other shifts in cost-effectiveness presented in Figs. 14-16 are discussed below.

When the NIB model is exercised with EPA versus AUSM coal data, differences in the computed cost-effectiveness estimates arise principally because of the differences in marginal costs between the two data sets. That is, each data set contains a base coal (i.e., selected to meet the regulatory baseline) for each region plus several alternative coals (i.e., selected to meet various regulatory options). Tables 10 and 11 list these coals and their respective characteristics. As is seen, the coals in the two data sets are different; thus, their marginal costs of meeting an emission limit would also differ. Besides differences in marginal costs, the emission limit at which it becomes more economic to install an FGD system than purchase a more expensive coal also differs between the two data sets.

When emission reductions are achieved through fuel switching, the difference in cost-effectiveness between the two data sets is principally the result of comparative marginal cost variances between the base case coal and more-expensive low-sulfur coal. It should be noted that in the NIB model, coals available to an industrial boiler are held fixed within a region; however, boiler size will affect the base-case coal selected and the marginal cost of purchasing low-sulfur coals.

In those situations where both EPA and AUSM coals achieve lower emissions through FGD systems, differences in cost-effectiveness estimates are the result of (1) cost savings achieved by switching from the base coal to a cheaper higher-sulfur coal and (2) the marginal cost of increasing scrubber efficiency when burning a high-sulfur coal. In general, it is more cost-effective to burn an inexpensive high-sulfur coal and increase scrubber efficiency than to scrub a low-sulfur coal at a low efficiency. If the cost savings obtained by switching from a low- to a higher-sulfur coal are minimal, they may be offset or even exceeded by an increase in FGD costs resulting from higher removal efficiencies. An example of where no coal cost savings are achieved is when an FGD system is used with AUSM coals in Region 8. Normally, the cheapest coals have the highest sulfur content and thereby require the greatest FGD removal efficiency. In Region 8, however, the cheapest available AUSM coal is also the lowest in sulfur content. The NIB model selected this coal type to meet all SO_2 emission limits, even when an FGD system was used. In effect, this resulted in a low removal efficiency for the FGD system, and no coal cost savings from switching to a lower-cost but higher-sulfur coal.

Both increases and decreases in marginal coal costs relative to the base coal are important in determining the emission limit at which it becomes economic to install an FGD system. For example, when low-sulfur coal is relatively inexpensive, and cost savings from switching to a high-sulfur coal are small or nonexistent (i.e., the cost versus SO_2 emission rate curve is relatively inelastic), FGD systems will only be installed at very low emission limits. For steeper (i.e., more elastic) cost versus SO_2 emission rate curves, FGD systems will be installed at relatively higher emission limits. Although marginal coal cost differences between the two coal data sets are comparable, the coal cost curves tend to be somewhat steeper for the EPA data than for the AUSM data. Therefore, when the EPA coal data set is used, FGD systems are installed at lower emission limits than when the AUSM data set is used.

5.2 LIKELIHOOD OF COAL USE IN NEW INDUSTRIAL BOILERS

Steam-generating units subject to the proposed NSPS regulations (51 FR 22384) are those that will be purchased during the next five years.* The relative importance of coal as fuel for these boilers was evaluated by comparing the total levelized cost of using coal and oil under current and projected fuel prices. Details of this evaluation are contained in the appendix.

This question of fuel type for industrial boilers is important to the discussion of regulatory options because of its implications for the size of the coal-fired boiler population and ultimately the impact of the proposed NSPS revisions. If, as demonstrated in the appendix, the coal-fired boiler population is small because such

*A five-year time frame is used because all NSPS are subject to review on a five-year basis. In the past, there has been some variation in this schedule.

boilers are uneconomic under current and future fossil fuel prices, then the corresponding environmental benefits from the proposed NSPS revisions (examined in this report) would also be small. However, if tighter standards are imposed nonetheless, the cost impacts on individual boilers are likely to be unnecessarily high. Consequently, it is important to adopt the appropriate revisions to the industrial boiler NSPS so that total impacts are minimized.

The evaluation presented in the appendix indicates that, in 1983 dollars, oil costs would have to rise to approximately $\$5.50/10^6$ Btu ($34/bbl) in the West, and to about $\$7.00/10^6$ Btu ($44/bbl) in the East in order for coal to be the preferred fuel for a 100 x 10^6 Btu/h boiler meeting the regulatory baseline. For a 250 x 10^6 Btu/h boiler, the crossover points for selecting coal are lower: oil prices must be $\$3.65/10^6$ Btu in the West and $\$5.30/10^6$ Btu in the East. The crossover point is even lower for large boilers (>400 x 10^6 Btu/h): $\$3.30/10^6$ Btu in the East and about $\$5.00/10^6$ Btu in the West.

In the 1985-1990 time frame, oil prices are expected to be approximately $20/bbl, which is equivalent to $\$3.20/10^6$ Btu.[11] This indicates that, under regulatory baseline conditions, the only new boilers for which coal can be burned as cheaply as oil are large boilers (in the 400 x 10^6 Btu/h size range) in the western United States. However, it is also in this region that the price of natural gas is projected to remain low. Thus, it can be reasonably expected that oil and gas will compete effectively for the industrial boiler market share during the next five years. Such an outlook reduces the importance of the proposed regulations since industrial boilers will likely be burning oil and gas rather than coal.

6 STUDY FINDINGS

This study presents an analysis of the relevant costs and emissions reduction potential from compliance with the proposed revisions to NSPS for SO_2 emissions from industrial boilers. It examines a variety of regulatory options for achieving SO_2 emission reductions, using cost-effectiveness, defined in relation to emissions and compliance costs under current regulations, as one of the key bases for comparison. To conduct the study, a model was developed that, based on regional coal quality and costs, selects the least-cost method or methods for complying with a given regulatory option. Also produced are estimates of emissions, annualized cost, and cost-effectiveness associated with each option. Most of the control cost algorithms and other supporting information used in the model are from EPA. Key findings from the study are summarized below.

6.1 REGULATORY BASELINE

- The baseline emission rate used by EPA is considerably less stringent than typical emission rates contained in EPA-approved permits. The EPA analysis of the proposed standard produced lower cost-effectiveness values than would occur if typical emission rates were used.

- The following definition of the regulatory baseline was considered to be appropriate, based on EPA and state permit data: (1) 1.2 lb $SO_2/10^6$ Btu for boilers $\geq 250 \times 10^6$ Btu/h nationwide and for boilers $>100 \times 10^6$ Btu/h in Regions 6 and 8-10 and (2) 1.6 lb $SO_2/10^6$ Btu for boilers greater than 100 and less than 250×10^6 Btu/h in Regions 1-5 and 7.

6.2 REGULATORY OPTIONS

6.2.1 Mandatory Percentage Removal Options

- For 100×10^6 Btu/h boilers in Regions 3, 5, and 8, cost-effectiveness estimates are \$1,700-\$2,500/ton.

- For 250 and 400×10^6 Btu/h boilers, cost-effectiveness estimates are about \$1,500 and \$1,000/ton, respectively.

- Cost-effectiveness is less than \$1,000/ton only for 400×10^6 Btu/h boilers in Region 3. Cost-effectiveness is lower for this combination of boiler size and region because the NIB model determines that these boilers would use FGD systems to meet the current regulatory baseline; hence, any cost increase under the regulatory scenario only reflects the cost of increasing FGD removal efficiency and not the total scrubber cost.

6.2.2 Emission Limitation Options

- Under emission limitation options, the minimum cost-effectiveness for all boiler sizes and regions corresponds with emission ceilings in the 0.7-1.0 lb $SO_2/10^6$ Btu range. To meet this limit, these boilers use cleaned coal. Lower emission ceilings necessitate use of FGD systems and result in substantial incremental cost increases.

- The emission ceilings of 1.0-1.4 lb $SO_2/10^6$ Btu are achieved by burning low-sulfur coal. Thus, the cost increases for these scenarios are largely attributable to incremental fuel costs and monitoring costs.

- The most cost-effective emission ceiling for 100 x 10^6 Btu/h boilers in all three regions is 0.8 lb $SO_2/10^6$ Btu, which is achieved by burning cleaned coal. However, the cost-effectiveness values are around $2,000/ton; the minimum value computed is $1,661/ton in Region 5.

- For 250 and 400 x 10^6 Btu/h boilers, cost-effectiveness estimates generally range from approximately $1,000 to $2,000/ton for all emission ceilings evaluated.

- For 400 x 10^6 Btu/h boilers in Regions 5 and 8, cleaned coal combustion is the least-cost method for meeting 0.9 and 0.7 lb $SO_2/10^6$ Btu emission ceilings, respectively. For lower ceilings, FGD systems are selected.

6.2.3 Continuous Emission Monitoring Requirements

- A CEM requirement distorts the cost and cost-effectiveness of compliance-coal options versus technology-dependent approaches such as FGD. For some small boilers, the annual costs of monitoring would exceed the annual costs of emissions compliance.

- Cost-effectiveness estimates are sensitive to CEM requirements for all emission ceilings. Eliminating the CEM requirement for coal-fired boilers meeting emission ceilings without the use of FGD systems changes cost-effectiveness estimates from $800/ton to over $2,000/ton for 100 x 10^6 Btu/h boilers. Differences for 250 x 10^6 Btu/h boilers are about $500/ton and $1,000/ton in eastern and western regions, respectively.

- The most cost-effective regulatory option for coal-fired boilers in the 100-250 x 10^6 Btu/h range is an emission ceiling in the 0.8 to 1.2 lb $SO_2/10^6$ Btu range, with the CEM requirements as specified in the current NSPS regulations.

6.2.4 Emission Credits for Cogeneration and Nonfossil Fuel Combustion

- The incremental costs for not allowing credit for a coal-fired boiler in a combined-cycle cogeneration system (receiving 25% of its heat input from oil-fired turbine exhaust) range from a few hundred to a few thousand dollars per ton of SO_2.

- Incremental costs are lowest for boilers operating with existing FGD systems in the credit and noncredit situations.

- Incremental costs are highest when credit is not allowed and the turbine exhaust heat input necessitates use of an FGD system, relative to situations allowing credit.

- For boilers receiving 25% of their heat input from wood, the incremental costs of not allowing credit for the nonfossil fuel use are similar to the cogeneration values.

- Nonfossil fuel credits can be significant for coal-fired, combined-cycle cogeneration or multifuel boilers in situations where there is a marginal choice between compliance coal and FGD. For certain emission ceilings, the credit may allow use of lower-cost compliance coal options.

6.3 ALTERNATIVE COAL PRICES

- The cost-effectiveness of regulatory options and the least-cost control method for complying with them are sensitive to the coal sulfur content and cost assumed. Given the availability of very low sulfur coal, the least-cost method of complying with moderate emission ceilings is firing low-sulfur coal, even at substantial incremental cost, instead of relying on FGD systems.

- The EPA coal cost data appeared too high with only minor variations in cost as a function of sulfur content and with no very-low-sulfur coals available.

- The largest effect of using AUSM rather than EPA coal data is in Region 3. There, 400×10^6 Btu/h boilers select low-sulfur coal to meet a 1.0 lb $SO_2/10^6$ Btu ceiling, whereas the same boilers are predicted to use FGD with the EPA coal data. Similarly, in this region, 250×10^6 Btu/h boilers select low-sulfur coal to meet a ceiling of 0.8 lb $SO_2/10^6$ Btu.

- In Region 8, the least-cost option of meeting the most stringent emission ceiling considered, 0.6 lb $SO_2/10^6$ Btu, shifts from using an FGD system, based on EPA coal data, to burning low-sulfur coal, based on AUSM coal data.

- Cost-effectiveness estimates based on the AUSM coal data tend to be slightly lower than those based on the EPA data for 100×10^6 Btu/h boilers and slightly larger for 250 and 400×10^6 Btu/h boilers in Regions 3 and 5. In Region 8 the AUSM data result in substantially higher cost-effectiveness estimates (e.g., $5,740/ton compared to $2,160/ton for meeting a 0.6 lb $SO_2/10^6$ Btu ceiling for a 250×10^6 Btu/h boiler).

6.4 LIKELIHOOD OF COAL USE IN NEW INDUSTRIAL BOILERS

- Projections of the amount of coal burned in new industrial boilers are contingent on assumptions about future fuel prices.

- Based on a simplified comparison of total levelized costs for coal- and oil-fired boilers, oil prices would have to rise to $35-45/bbl in order for coal to compete effectively as an industrial boiler fuel. With natural gas and residual oil prices projected to be $26/bbl and $24/bbl (in 1983 dollars) in the year 2000, respectively, there is little incentive to construct new coal-fired industrial boilers. Thus, EPA may be overstating the environmental benefits (i.e., reduced emissions) of the proposed revision.

APPENDIX:

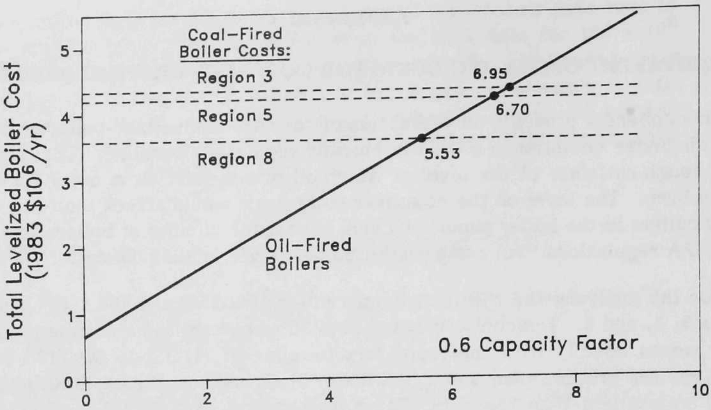
EQUIVALENT OPERATING COSTS FOR COAL-AND OIL-FIRED BOILERS

This appendix presents an evaluation of the total annualized boiler cost for firing coal and oil under compliance with the current regulatory baseline. The purpose is to provide a rough estimate of the level at which oil prices must be in order for coal to be cheaper to burn. The level of the crossover point price would affect the total number of coal-fired boilers in the boiler population and, hence, the number of boilers subject to the proposed EPA regulations. All costs presented below are in 1983 dollars.

For the analysis, the NIB model was run for 100, 250, and 400 x 10^6 Btu/h boilers in Regions 3, 5, and 8. The coal prices in Table 10 were used to determine the least-cost coal that would comply with the regulatory baseline of (1) 1.2 lb $SO_2/10^6$ Btu for all coal-fired boilers greater than 250 x 10^6 Btu/h in all regions, (2) 1.2 lb $SO_2/10^6$ Btu for coal-fired boilers less than 250 x 10^6 Btu/h in Region 8, and (3) 1.6 lb $SO_2/10^6$ Btu for coal-fired boilers between 100 and 250 x 10^6 Btu/h in Regions 3 and 5. The oil prices used ranged from \$0 through \$9.00/10^6 Btu.

Figure A.1 presents annualized cost estimates for a 100 x 10^6 Btu/h boiler at 0.6 and 0.4 capacity factors. As the figure indicates, at a 0.6 capacity factor, coal only becomes cheaper than oil to burn when oil prices are \$5.53/10^6 Btu (\$35/bbl) in Region 8, \$6.70/10^6 Btu (\$42/bbl) in Region 5, and \$6.95/10^6 Btu (\$44/bbl) in Region 3. For this boiler size, a reduction in the capacity factor to 0.4 increases the crossover point from oil to coal by about \$1.50/10^6 Btu (\$9.40/bbl).

Figures A.2 and A.3 present analogous estimates for 250 and 400 x 10^6 Btu/h boilers, respectively. At an oil price of \$3.65/10^6 Btu (\$23/bbl), coal becomes cheaper than oil to burn in a 250 x 10^6 Btu/h boiler with a 0.6 capacity factor in Region 8. In Regions 3 and 5, oil would have to reach a price of about \$5.30/10^6 Btu (\$33/bbl) in order for coal to become cost-competitive for this boiler size. For 400 x 10^6 Btu/h with a 0.6 capacity factor, the oil-to-coal crossover point is reduced slightly, to about \$3.30/10^6 Btu for oil (\$21/bbl) in the West and \$5.00/10^6 Btu (\$31/bbl) in the East.



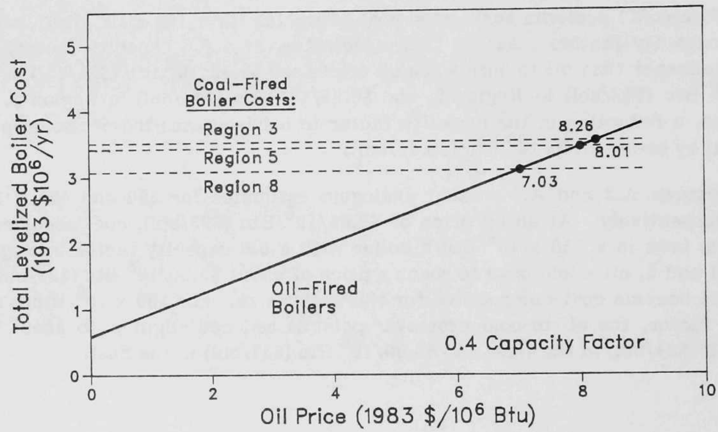


FIGURE A.1 Total Levelized Boiler Costs by Oil Price under Compliance with the Regulatory Baseline, Showing Regional Crossover Point Prices between Coal and Oil: 100 x 10^6 Btu/h Boilers

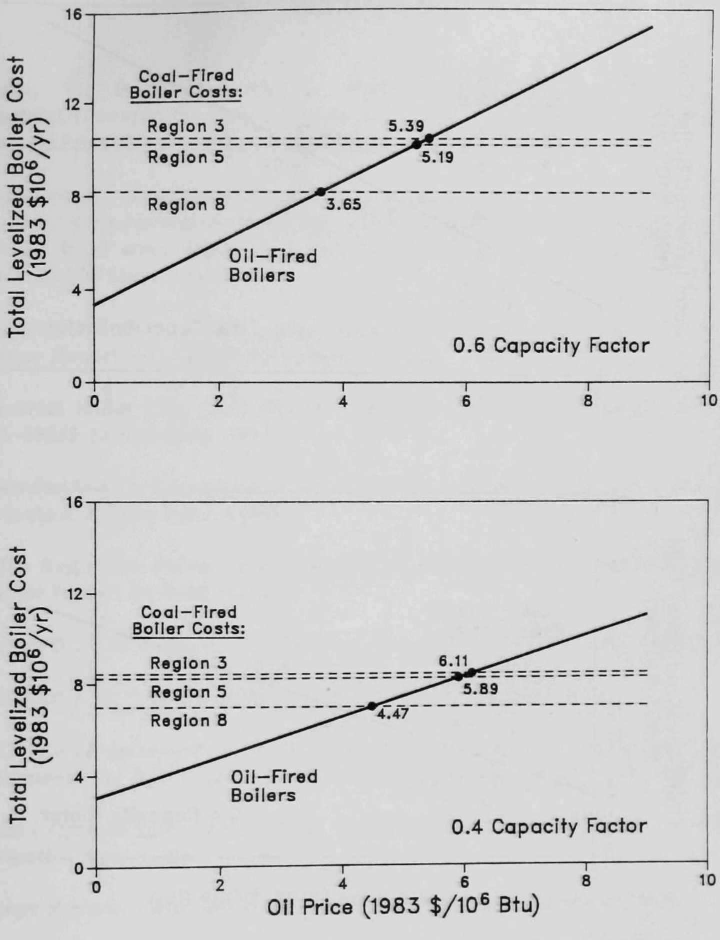


FIGURE A.2 Total Levelized Boiler Costs by Oil Price under Compliance with the Regulatory Baseline, Showing Regional Crossover Point Prices between Coal and Oil: 250 x 10^6 Btu/h Boilers

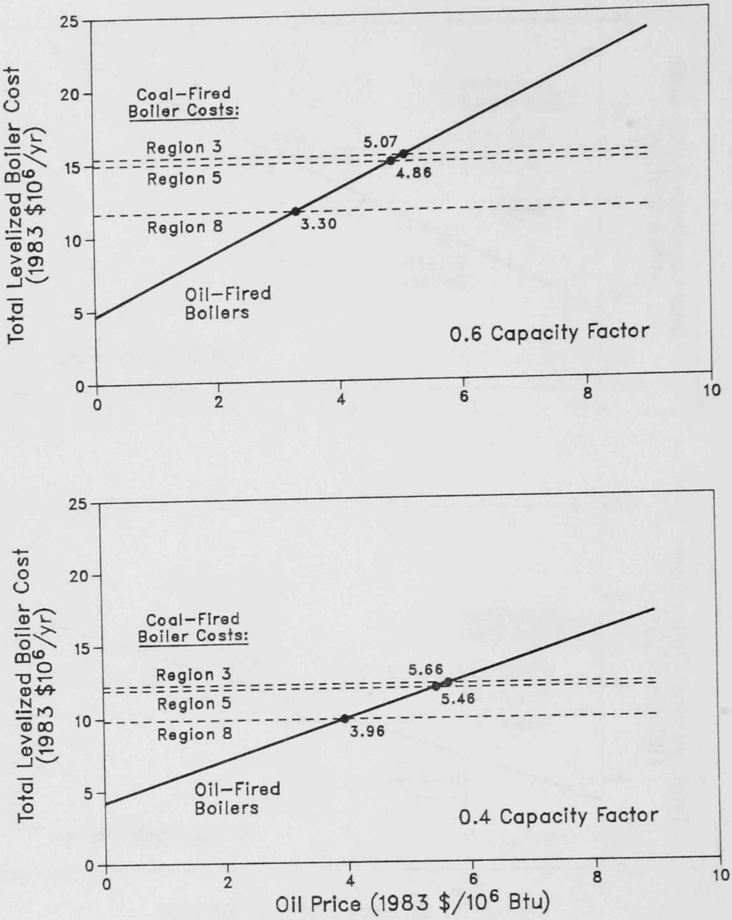


FIGURE A.3 Total Levelized Boiler Costs by Oil Price under Compliance with the Regulatory Baseline, Showing Regional Crossover Point Prices between Coal and Oil: 400 x 10^6 Btu/h Boilers

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